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
PRC-025-2

Shamai Elstein
Senior Counsel
Lauren A. Perotti
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
shamai.elstein@nerc.net
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

March 16, 2018

TABLE OF CONTENTS

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
PRC-025-2

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 for Commission approval proposed Reliability Standard PRC-025-2 - Generator Relay Loadability. The PRC-025 Reliability Standard addresses setting load-responsive protective relays associated with generation Facilities[4] at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Proposed Reliability Standard PRC-025-2 improves upon currently-effective Reliability Standard PRC-025-1 by addressing certain relay setting application issues and by clarifying certain terminology and references. NERC requests that the Commission approve the proposed Reliability Standard (**Exhibit A**) and find that the proposed standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests that the Commission approve: (i) the associated Implementation Plan (**Exhibit B**); (ii) the associated

1 16 U.S.C. § 824o (2012).

2 18 C.F.R. § 39.5 (2017).

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).

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

Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), which remain unchanged from PRC-025-1 (**Exhibit D**); and (iii) the retirement of currently-effective Reliability Standard PRC-025-1.

As required by Section 39.5(a)[5] of the Commission's regulations, this Petition presents the technical basis and purpose of the proposed Reliability Standard, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**), and a summary of the standard development history (**Exhibit E**). The proposed Reliability Standard was adopted by the NERC Board of Trustees on February 8, 2018.

This Petition is organized as follows: Section I of the Petition presents an executive summary of the proposed Reliability Standard. Section II of the Petition provides the individuals to whom notices and communications related to the filing should be provided. Section III provides background on the regulatory structure governing the Reliability Standards approval process. This section also provides information on the development of the proposed Reliability Standards through Project 2016-04 - Modifications to PRC-025-1. Section IV of the Petition provides a detailed discussion of the proposed Reliability Standard and explains how the proposed standard enhances reliability and improves flexibility in applying the various options. Section V of the Petition provides a summary of the proposed implementation plan.

I. <u>EXECUTIVE SUMMARY</u>

Proposed Reliability Standard PRC-025-2 adds enhancements to the currently-effective generator loadability standard PRC-025-1, to better address risks of unnecessary generator

---

[5] 18 C.F.R. § 39.5(a).

[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).

tripping where the voltage is depressed and the generator is capable of increased Reactive Power output and voltage support during the disturbance. During the implementation of Reliability Standard PRC-025-1, NERC and industry identified the need to revise the standard to address certain applications and to clarify language to advance the reliability goals of the standard. These revisions are reflected in proposed Reliability Standard PRC-025-2. Specifically, the proposed Reliability Standard:

1. adds a provision to Attachment 1, Table 1 Relay Loadability Evaluation Criteria to address dispersed power producing resources that are unable to be set at 130% of the calculated current due to physical limitations of the protection equipment;
2. adds to the Table 1 relay type description the protective relay 50 Element associated with instantaneous (i.e., without intentional time delay) tripping of overcurrent based protection;
3. clarifies, in the Table 1 Application column, that an entity must apply settings to all the applications described therein;
4. clarifies that an entity, when employing simulation for setting relays associated with the transmission line interconnecting the generator or plant to the Transmission system, must simulate the 0.85 per unit depressed voltage at the remote end (i.e., Transmission system side) of the line;
5. removes the term "Pick Up" from the Attachment 1, Table 1 heading (so that the new heading reads "Setting Criteria"), to better align the setting to the calculated or simulated capability of the generator with an associated margin; and
6. clarifies certain terminology and references.

For the reasons explained more fully in this Petition, NERC requests that the Commission approve proposed Reliability Standard PRC-025-2 and find that the proposed 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:[7]

Shamai Elstein*
Senior Counsel
Lauren A. Perotti*
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
shamai.elstein@nerc.net
lauren.perotti@nerc.net

Howard Gugel*
Director of Standards
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560
(404) 446-2595 – facsimile
howard.gugel@nerc.net

III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System ("BPS"), and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each new Reliability Standard that the ERO proposes should become mandatory

[7] 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 (2017), to allow the inclusion of more than two persons on the service list in this proceeding.

[8] 16 U.S.C. § 824o.

[9] *Id.* § 824o(b)(1).

[10] *Id.* § 824o(d)(5).

[11] 18 C.F.R. § 39.5(a).

and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c)[13] 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 Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[14] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[15]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[16] and thus satisfy certain of the criteria for approving Reliability Standards.[17] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the

---

12 16 U.S.C. § 824o(d)(2).

13 18 C.F.R. § 39.5(c)(1).

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

15 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.

16 *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

17 Order No. 672 at PP 268, 270.

comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

C. Project 2016-04 Modifications to PRC-025-1

On July 17, 2014, the Commission issued Order No. 799 approving Reliability Standard PRC-025-1.[18] Reliability Standard PRC-025-1 was developed in response to certain Commission directives in Order No. 733[19] to develop a standard governing generator protective relay loadability. Reliability Standard PRC-025-1 requires applicable Generator Owners, Transmission Owners, and Distribution Providers to apply an appropriate setting for load-responsive relays based on calculations or simulations for conditions established in Attachment 1 of the standard. The Attachment 1 criteria are representative of the short-term conditions during which generation Facilities have, in the past, disconnected when otherwise capable of providing Reactive Power. Under the phased implementation plan for PRC-025-1, applicable entities have between five and seven years to become compliant with the standard, depending on the scope of work required.

In the course of implementing Reliability Standard PRC-025-1, industry identified issues for specific Facility applications and load-responsive protective relays. To address these issues, NERC initiated Project 2016-04 Modifications to PRC-025-1 in September 2016. The standard authorization request for this project directed the standard drafting team ("SDT") to consider revisions to the standard that would:

---

[18] *Generator Relay Loadability and Revised Transmission Relay Loadability Reliability Standards*, Order No. 799, 148 FERC ¶ 61,042 (2014). In this order, the Commission also approved Reliability Standard PRC-023-3, which included clarifying changes to PRC-023-2 to establish a bright line between the applicability of load-responsive protective relays in the transmission and generator relay loadability Reliability Standards.

[19] *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 61,221 (2010) (Order No. 733); *order on reh'g and clarification*, Order No. 733-A, 134 FERC ¶ 61,127; *clarified*, Order No. 733-B, 136 FERC ¶ 61,185 (2011).

- Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed power producing resources.
- Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard.
- Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s), thereby misapplying the loadability margins to relays for the stated application(s).
- Prevent a lowering of dependability of protective relays directional toward the Transmission system at generating facilities that are remote to the transmission network.
- Modify or eliminate the use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to "not trip" based on the criteria in Table 1.
- Clarify miscellaneous aspects of the standard, Attachment 1, and/or the Application Guidelines.

The SDT revised the PRC-025 standard to address the issues summarized above and to clarify language. Following two comment and ballot periods, proposed Reliability Standard PRC-025-2 was approved by the ballot pool on January 18, 2018. The NERC Board of Trustees adopted the proposed standard on February 8, 2018.

IV. JUSTIFICATION FOR APPROVAL

As discussed in **Exhibit C** and below, proposed Reliability Standard PRC-025-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Proposed Reliability Standard PRC-025-2 continues to consist of a single Requirement, Requirement R1, which requires entities to apply settings that are in accordance with Attachment 1: Relay Settings on each applicable load-responsive protective relay while maintaining reliable fault protection. The majority of the revisions in proposed PRC-025-2 are in Attachment 1. Corresponding revisions have been made to the Guidelines and Technical Basis material following the standard. A summary of the proposed standard revisions and the justification for each is provided below. The proposed revisions are shown in the PRC-025-2 redline attached to this Petition as **Exhibit A**.

A. Revisions to Address Dispersed Power Producing Resources

Reliability Standard PRC-025-1 Table 1 Option 5 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of dispersed power producing resources to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate megavolt-ampere (MVA) output at rated power factor. In some cases, manufacturer requirements or the physical limitations of dispersed power producing resources may prevent the entity from being able to achieve the 130% threshold. For example, the entity may exceed a manufacturer's warranty or design criteria when applying 130% margin to the calculated current based on the aggregate output or individual resource. As an example of a physical limitation, the physical size of the resource may prevent the entity from being able to install a larger breaker frame in order to meet the 130% margin. Other limitations include the inability of the resource to produce a level of current that would be capable of reaching the 130% threshold; many asynchronous resources (e.g., inverters) are only capable of producing 1.1 to 1.2 per unit (110-120%) of their rated output.

To ensure that the load-responsive protective relays associated with asynchronous generation Facilities may be set at a level to prevent unnecessary tripping during a system disturbance, the proposed Reliability Standard PRC-025-2 Table 1 adds an alternative setting option, Option 5b.[20] Option 5b is available for inverter based machines that cannot achieve the 130% threshold due to the limitations described above. Protective devices associated with this

[20] Current Option 5 remains in Table 1 as Option 5a for entities that have implemented the 130% setting.

equipment generally have adjustable trip values that allow the protection setting to be set not to infringe on the capability of the resource. Under new Option 5b, the overcurrent element shall be set greater than the maximum capability of the asynchronous resource and applicable equipment. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power control devices).[21] Option 5b refers to a new figure, Figure A, to demonstrate that the overcurrent element tripping characteristic shall not infringe upon the asynchronous resource capability.

The proposed standard also includes a new footnote 1 in the Applicability section concerning asynchronous resources. These resources are generally connected at voltages less than 1,000 volts. Footnote 1 clarifies that load-responsive protective relays include low-voltage protection devices that have adjustable settings.

B. Revisions to Address Non-Standard Relay Element Applications

Proposed Reliability Standard PRC-025-2 improves upon the currently-effective version of the standard by addressing the inclusion of the IEEE 50 device element[22] and other similar instantaneous (i.e., without intentional delay) overcurrent elements for the various overcurrent applications within Table 1. In practice, a 50 element is generally set with a very high pick up and well above the loadability levels determined by the standard. By including the 50 element in Table 1, the proposed standard clarifies that the 50 element must also achieve the same or greater level of loadability as the 51 element (i.e., with intentional delay). The inclusion of the 50

---

[21] *See* proposed Reliability Standard PRC-025-2 (Exhibit A), Guidelines and Technical Basis at 45.

[22] Device numbers are identified in Institute of Electrical and Electronics Engineers ("IEEE") Std. C37.2-2008, *IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. (2008). A citation to IEEE Standard C37.2-2008 is added to the Associated Documents section to clarify that the IEEE device numbers within the PRC-025-2 standard refer to typical protective device functions used by entities applying load-responsive protective relays to Elements on the BPS.

element avoids the potential for setting the 50 element inconsistent with the objectives of the standard and unknowingly creating a 51 element[23] by adding a definite time characteristic, which is applicable to the standard. Including the 50 element avoids the risk where the overcurrent element could be applied with a lower, less desirable loadability setting according to the applications in Table 1.

In addition, revisions are made in Attachment 1 to clarify that IEEE device numbering convention varies by manufacturer. For example, a voltage-restrained (i.e., V-R) relay is variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms as discussed in the Guidelines and Technical Basis section under the heading Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R). Likewise, manufacturers of low-voltage equipment generally use protective device trip unit designations for long-time delay, short-time delay, and instantaneous and are referred to as long (L), short (S), and instantaneous (I) as discussed in Attachment 1 under the narrative heading Table 1. Although low-voltage designations are not specifically identified in Table 1, their relationship to the IEEE device numbers are widely understood by industry protection engineers.

These revisions improve the PRC-025 standard by drawing attention to the potential loadability issues when using the 50 element and by increasing awareness that not all protective relays are designated by an IEEE device number.

C. Revisions to Clarify Application Column of Table 1

Proposed Reliability Standard PRC-025-2 reflects several revisions to clarify the Application column of Table 1. In several places in the Application column of Reliability Standard PRC-025-1 Table 1, it is not clear whether applicable protective relays associated with

[23] Any 50 element being applied with a definite time characteristic is, by the IEEE definition, a 51 element and applicable to the standard.

all listed Elements are to be set using the setting criteria of Table 1 or just one of the multiple listed Elements. For example, in Options 4, 5, and 6, the Application column provides: "Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources" (emphasis added). Entities could interpret the use of the "or" conjunction to require setting of only one particular application and not the other. To clarify that applicable protective relays associated with all listed Elements are to be set using the setting criteria in Table 1, revisions are proposed in the Application column of PRC-025-2 Table 1 for Options 1 through 6. The proposed language advances the goal of the Reliability Standard to ensure that loadability margins are applied to relays on all specified Elements from the generation resource to the Transmission system.

Other clarifications were made to Options 7 through 12 and 14 through 19 of Table 1 to remove the described location of the relay from the "Relay Type" column to the "Application" column.

D. Revisions to Address Dependability of Protective Relays that Interconnect Generating Facilities to the Transmission System

Proposed Reliability Standard PRC-025-2 contains revisions to Table 1 Options 14b, 15b, and 16b to address cases where the interconnecting Transmission line impedance impacts the maximum Reactive Power capability of the generator or plant. Where a generating Facility is generally small (i.e., electrically weak) and remote (i.e., as few as 20 miles) to the Transmission network, the maximum Reactive Power output capability can be significantly lower than the capability determined by the specific Table 1 Options. For these Facilities, setting load-responsive protective relays using the maximum resource capability without considering the effects of line impedance could result in an overly conservative loadability setting. An overly conservative setting could reduce relay dependability for clearing faults, create substantive difficulty in coordinating backup protection schemes, or result in the application of more complex and costly protective schemes (e.g., transfer-trip).

These revisions move the point of the system disturbance (i.e., 0.85 per unit nominal voltage) from the terminals of the generator step-up transformer to the remote end of the line to account for the effects of line impedance. This revision enhances reliability by improving dependability of load-responsive protective relays for clearing faults, reducing difficulty in coordinating backup protection schemes, and potentially eliminating the need for more complex and costly protective schemes.

E. Revisions to Address Use of Term "Pickup Setting"

Reliability Standard PRC-025-1 uses the term "pickup setting"; this term relates to initial measurements and specific detection methods (see, e.g., Table 1 "Pickup Setting Criteria"). The intent of the standard, however, is for relays to "not trip" based on the capability of the generator or plant, using the criteria in Table 1. To address this issue and avoid the assumption that an initial specific measurement is mandatory, the term "pickup" is eliminated from the fifth column of proposed Reliability Standard PRC-025-2 Table 1 so that it reads "Setting Criteria." Confirming changes are made in the Attachment 1 text preceding Table 1.

F. Miscellaneous Revisions to Attachment 1: Relay Settings

Revisions are proposed in PRC-025-2 Attachment 1 under the "Generators" heading to clarify that the phrase regarding unit capability "reported to the Transmission Planner" is a minimum criterion and that a greater unit capability is acceptable. Additionally, low voltage protection devices that do not have adjustable settings are now specifically listed under the list of Exclusions in Attachment 1. This change is consistent with the addition of the new footnote 1 in the Applicability section of the standard described above.

G. Revisions to PRC-025 Guidelines and Technical Basis

In accordance with the standard authorization request for this project, NERC has revised the Guidelines and Technical Basis section for proposed Reliability Standard PRC-025-2 to add supporting information regarding the above-described standard changes as well as provide clarification in several areas. For example, revisions have been made to clarify the various Figures, which illustrate the standard's applicability to a given configuration. As the Guidelines and Technical Basis section is not enforceable, NERC does not seek approval for these revisions but describes them for informational purposes only.

H. Enforceability of the Proposed Reliability Standard

The proposed Reliability Standard contains a VRF of High and VSL of Severe for the single standard Requirement, Requirement R1. The VRF and VSL remain unchanged from currently-enforceable Reliability Standard PRC-025-1. The VSL provides guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRF is one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRF assesses the impact to reliability of violating a specific Requirement.

In addition, the proposed Reliability Standard also includes a Measure that supports Requirement R1 by clearly identifying what is required and how the Requirement will be enforced. This Measure, which is unchanged from currently-enforceable Reliability Standard PRC-025-1, helps ensure that the Requirement will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

V. <u>EFFECTIVE DATE</u>

NERC respectfully requests that the Commission approve the proposed implementation plan attached to this Petition as Exhibit B. Under the proposed implementation plan, Reliability Standard PRC-025-2 would become effective on the first day of the first calendar quarter after regulatory approval. Reliability Standard PRC-025-1 would be retired immediately prior to the effective date of PRC-025-2.

Under the PRC-025-1 implementation plan, entities have either 60 or 84 months to come into compliance with the standard, as follows:

- 60 months, where the entity applies settings to its existing load-responsive relays that are capable of meeting the standard while maintaining reliable fault protection, or by October 1, 2019 for U.S.-based entities; or

- 84 months, where the entity needs to replace or remove its existing load-responsive protective relays, or by October 1, 2021.

The proposed PRC-025-2 implementation plan recognizes that entities are in the process of implementing the standard to meet these dates, but that certain revisions in PRC-025-2 may give reason for entities to re-evaluate their settings for load-responsive protective relays or require further time for implementation. The proposed PRC-025-2 implementation plan provides a new phased compliance schedule that is intended to supersede the phased compliance schedule provided in the currently-effective PRC-025-1 implementation plan. For existing Options, entities would have at least as much time to come into compliance with the proposed standard as they would have under the PRC-025-1 implementation plan. New phased compliance dates are provided for new and revised Table 1 Relay Loadability Evaluation Criteria Options, including:

- New Option 5b: 24 or 48 months, depending on whether replacement or removal is necessary;

- For the 50 element only in Options 2a, 2b, 2c, 5a, 5b, 8a, 8b, 8c, 11, 13a, and 13b: 60 or 84 months, depending on whether replacement or removal is necessary;

- Revised Options 14b, 15b, 16b: 24 or 48 months, depending on whether replacement or removal is necessary.

For load-responsive relays that later become applicable to the proposed standard, entities would continue to have 60 or 84 months to come into compliance, depending on whether replacement or removal is necessary.

The proposed implementation plan provides additional timing for new Option 5b due to the number of dispersed power generating resources that may be have been unable to apply the existing 130% threshold; however, the burden to adjust the settings to ensure the capability of the resource does not infringe on the protection setting is expected to be minimal.

The proposed implementation plan also provides a full 60 and 84 month implementation timeline to address the newly-added 50 element in certain Options. This timeline accounts for engineering review, potential equipment procurement, and outage coordination to commission the equipment and apply the appropriate settings.

Additionally, the proposed implementation plan allows entities sufficient time to address newly-revised Options addressing Transmission lines interconnecting the generating unit or plant to the Transmission system. The proposed timeframe allows entities to re-evaluate their settings to account for line impedance effects and to make appropriate modifications to the settings.

VI. CONCLUSION

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

- proposed Reliability Standard PRC-025-2 and associated elements included in **Exhibit A**;
- the implementation plan included in **Exhibit B**; and
- the retirement of currently-effective Reliability Standard PRC-025-1.

Respectfully submitted,

/s/ Lauren A. Perotti

Shamai Elstein
Senior Counsel
Lauren A. Perotti
Counsel
North American Electric Reliability Corporation
1325 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 400-3000
(202) 644-8099– facsimile
shamai.elstein@nerc.net
lauren.perotti@nerc.net

Counsel for the North American Electric Reliability Corporation

March 16, 2018

Exhibit A

Proposed Reliability Standard PRC-025-2 – Generator Relay Loadability

PRC-025-2 - Clean Version

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**
   4.1. Functional Entities:
   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.
   4.1.2. Transmission Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.
   4.1.3. Distribution Provider that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.
   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:
   4.2.1. Generating unit(s).
   4.2.2. Generator step-up (i.e., GSU) transformer(s).
   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]
   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.
   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.
5. **Effective Date:** See Implementation Plan

---

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. Background: After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf).

and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. **Evidence Retention:** The following evidence retention period(s) 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 Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, “Considerations for Power Plant and Transmission System Protection Coordination,” technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition.” (Date of Publication: March 2016)

IEEE C37.102-2006, “IEEE Guide for AC Generator Protection.” (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04
2	February 8, 2018	Adopted by NERC Board of Trustees	Revision

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>Setting Criteria</th></tr>
<tr><td rowspan="6">Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators</td><td rowspan="5">Phase distance relay (e.g., 21) – directional toward the Transmission system</td><td>7a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>7b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>7c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[7] If the relay is installed on the high-side of the GSU transformer use, Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[8] If the relay is installed on the high-side of the GSU transformer use, Option 16.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51)[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

A different application starts on the next page

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.
[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[13] If the relay is installed on the generator-side of the GSU transformer, use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) –connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[14] If the relay is installed on the generator-side of the GSU transformer, use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer, use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[17] If the relay is installed on the generator-side of the GSU transformer, use Option 12.

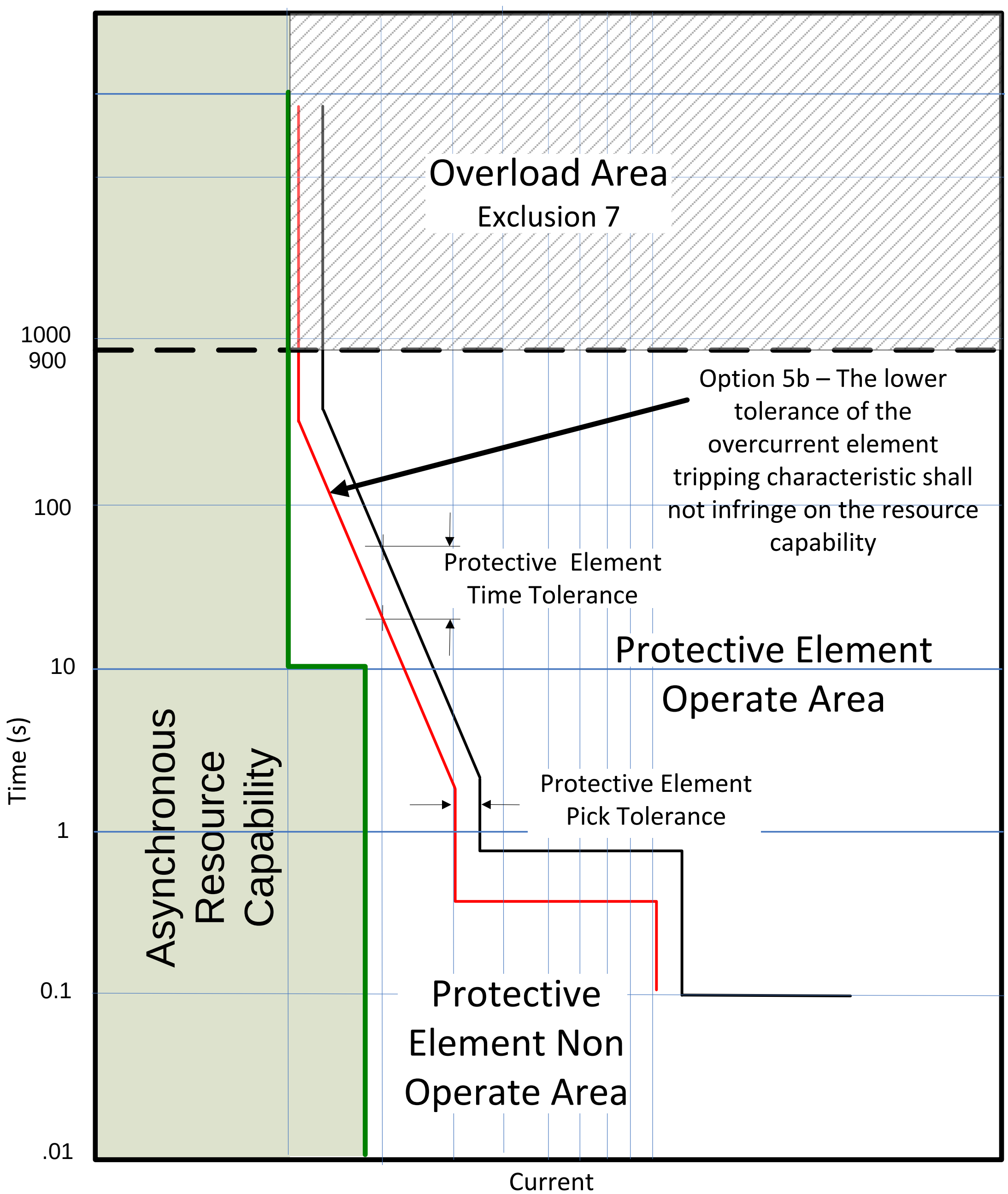


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

---

[18] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20 Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

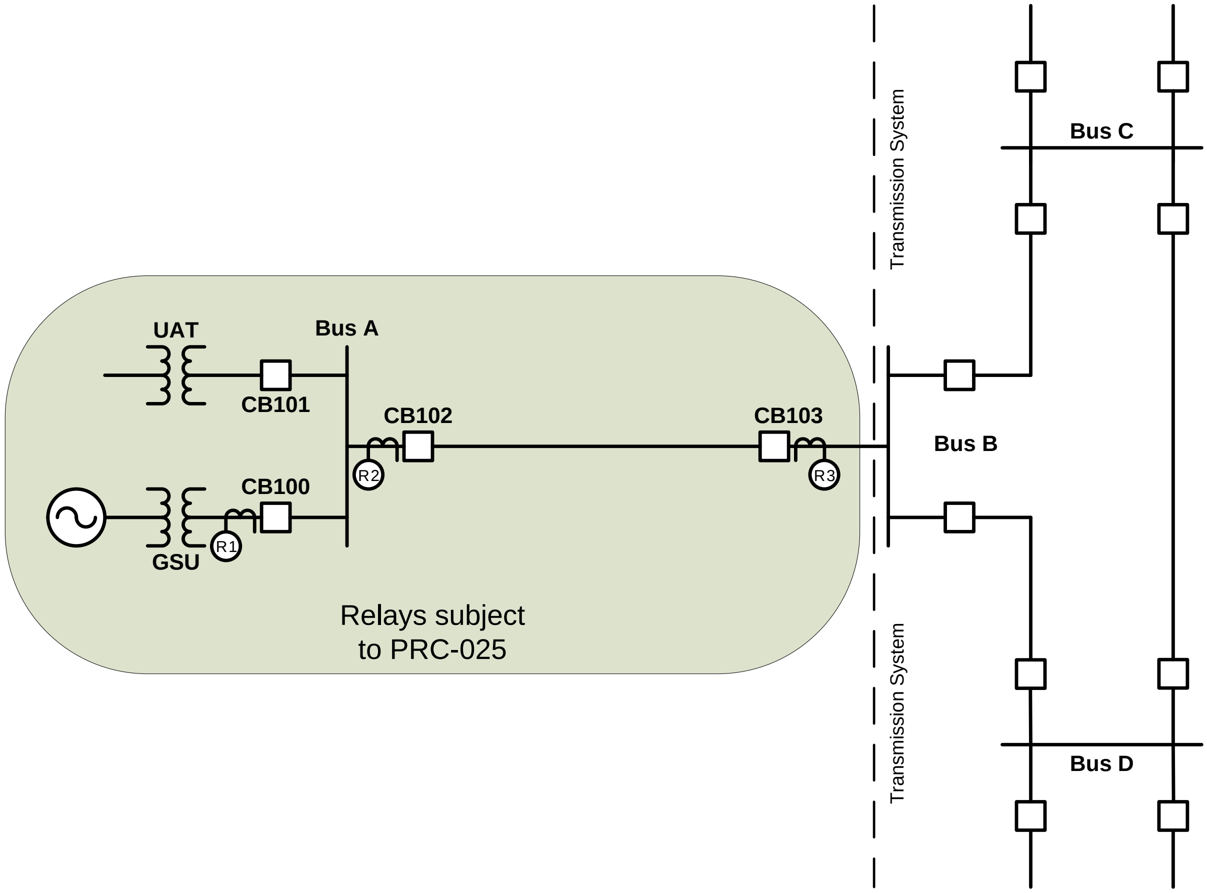


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

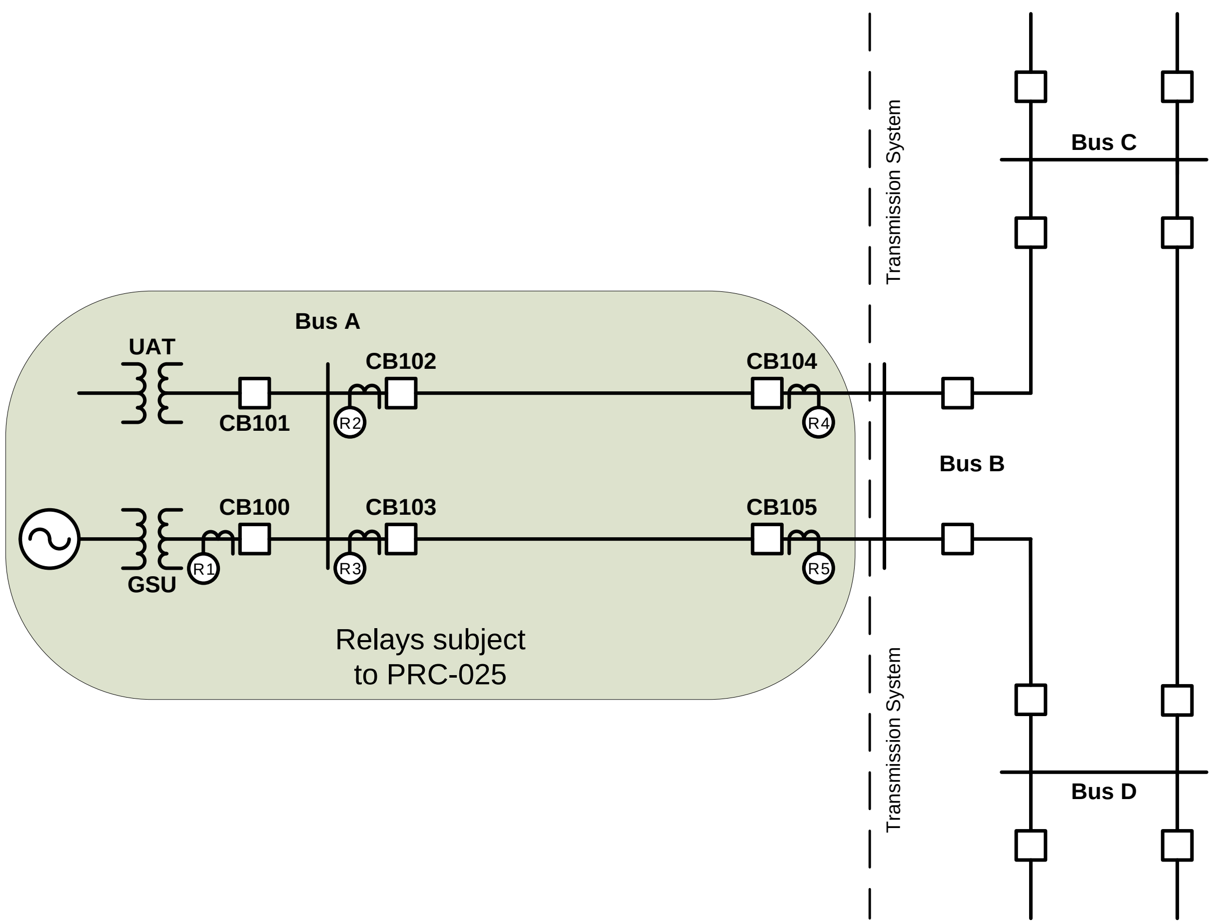


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

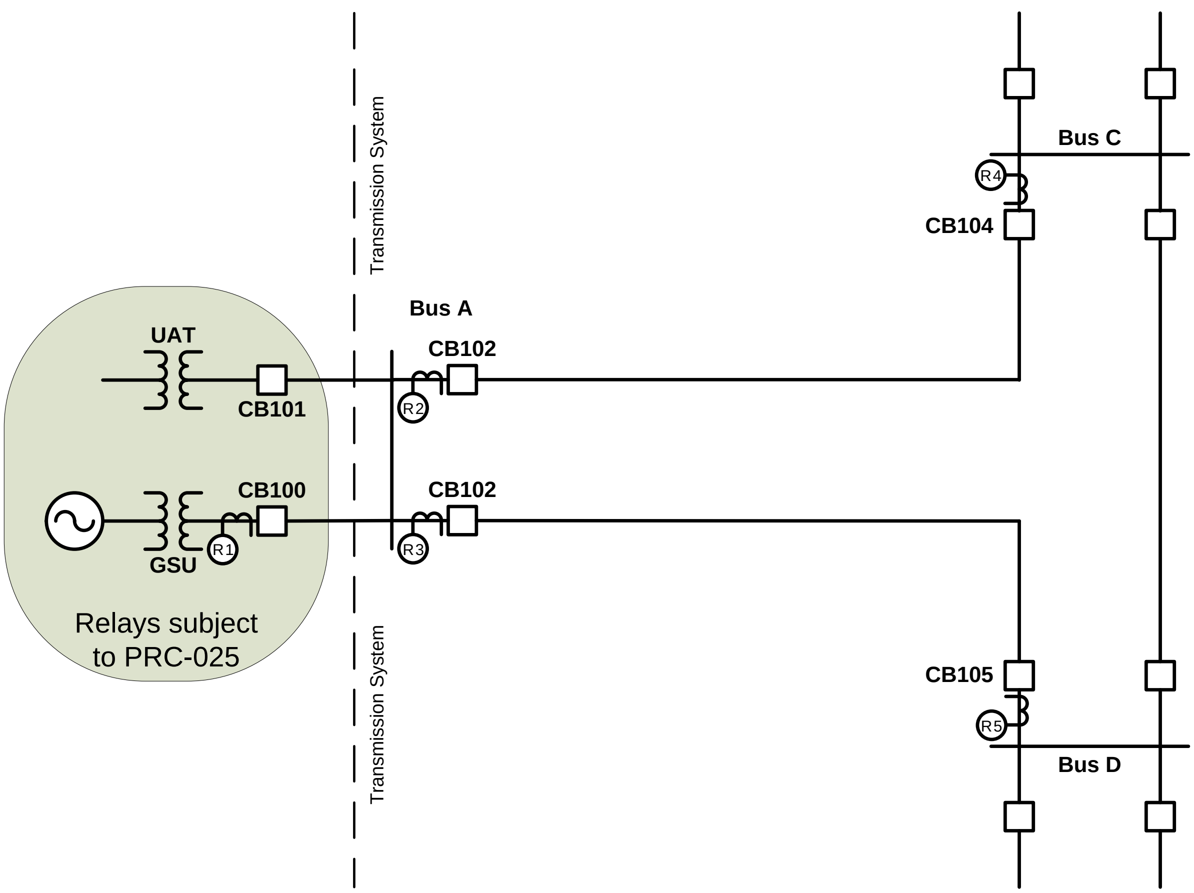


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system” or “feeders”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020 /NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

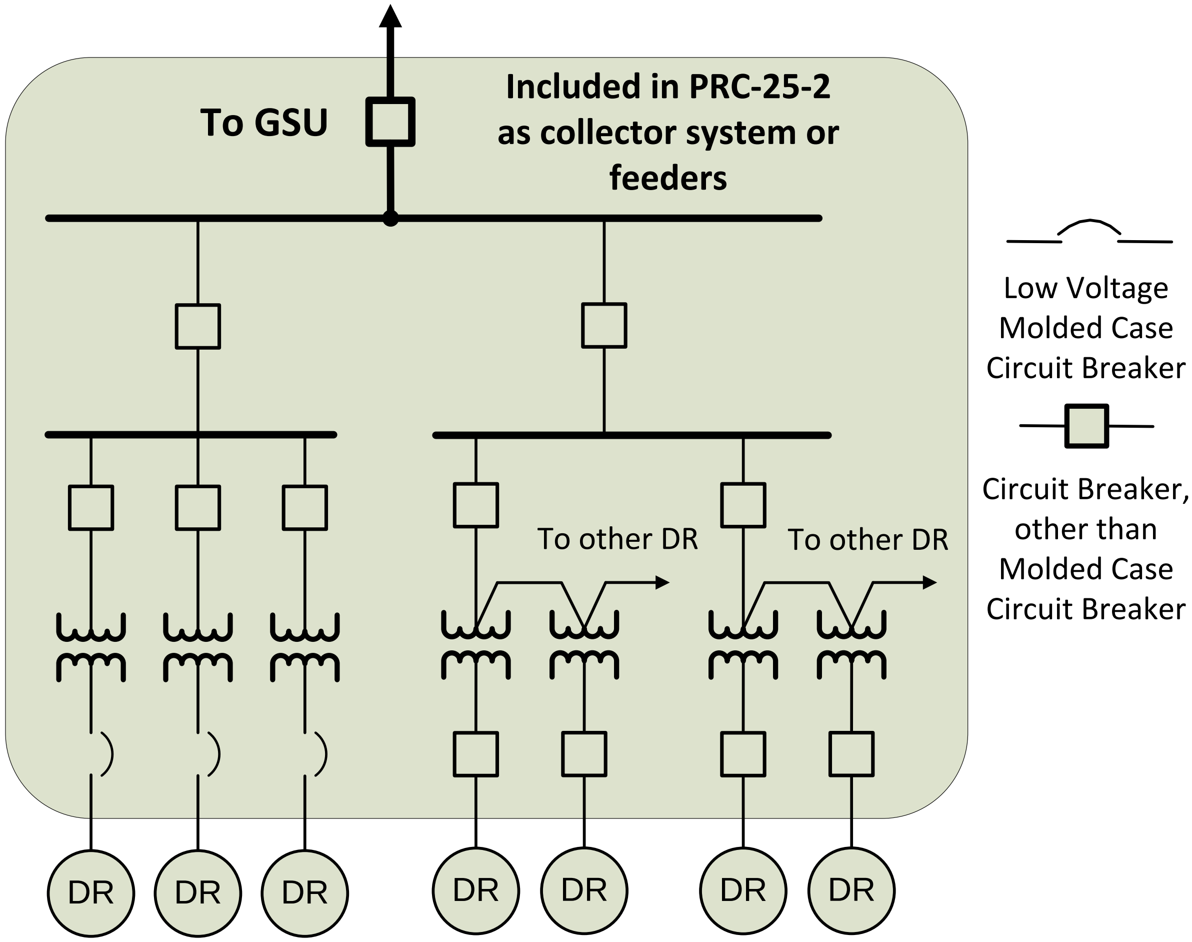


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column “Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

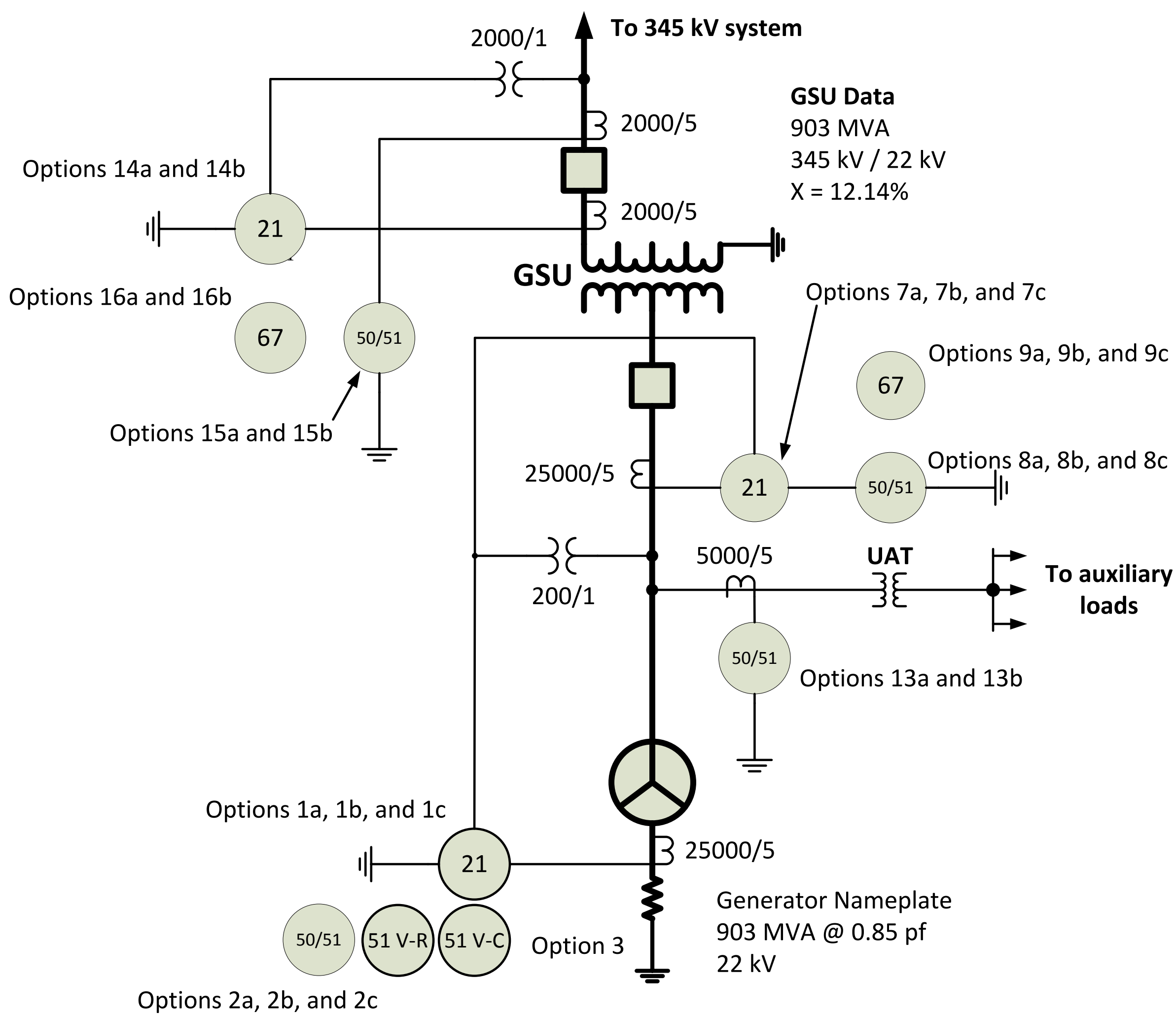


Figure 5: Relay Connection for corresponding synchronous options

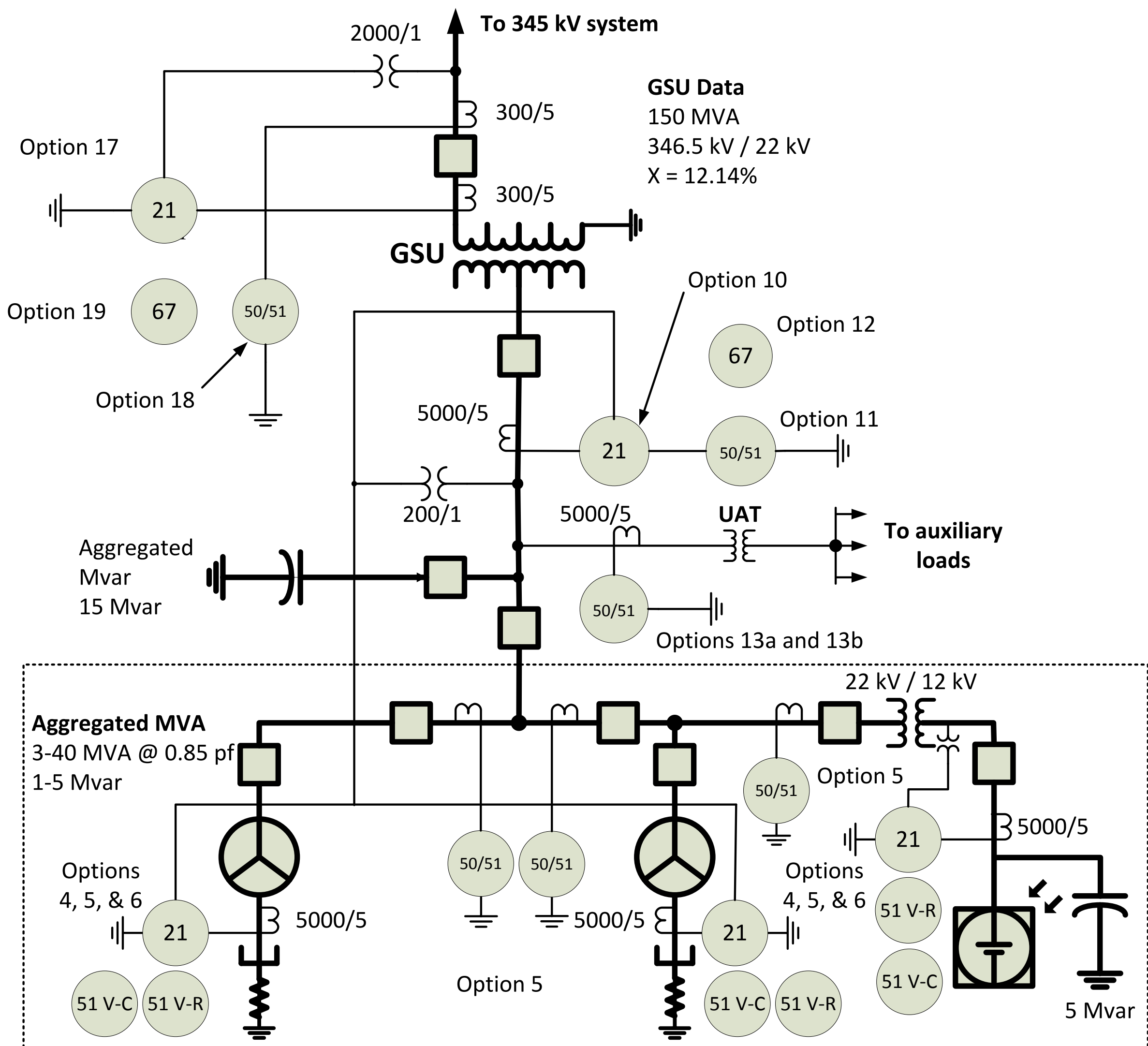


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

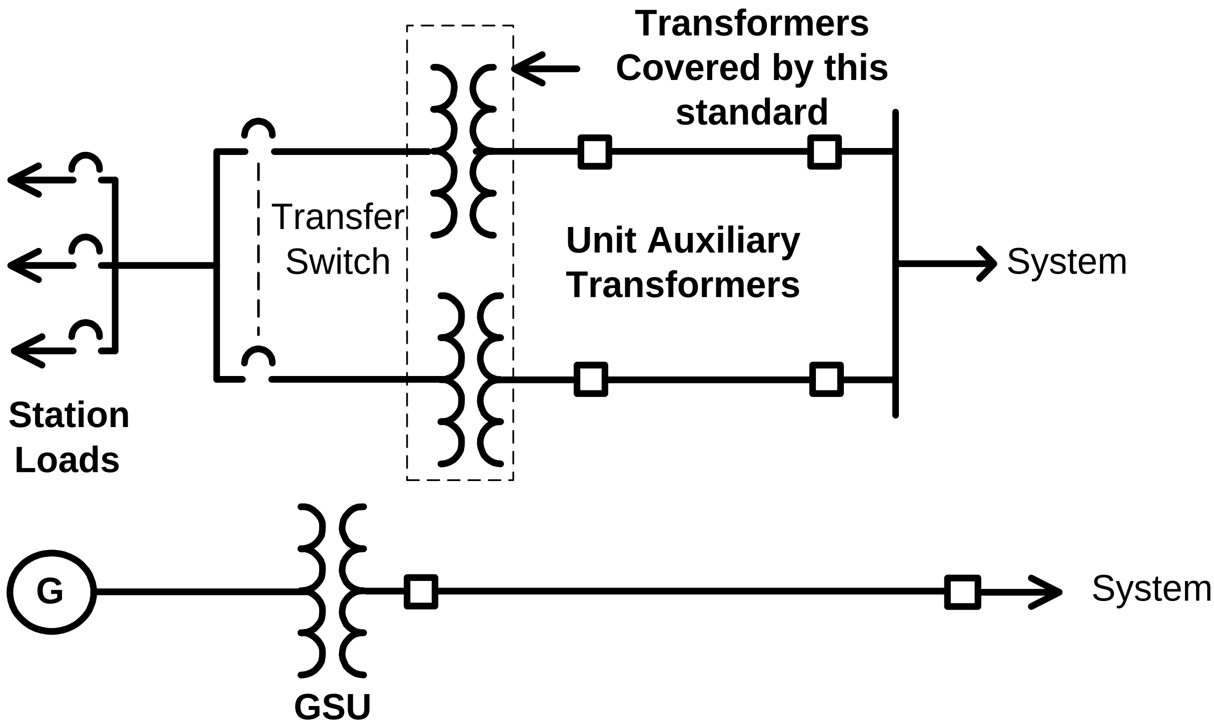


Figure 7: Auxiliary Power System (independent from generator)

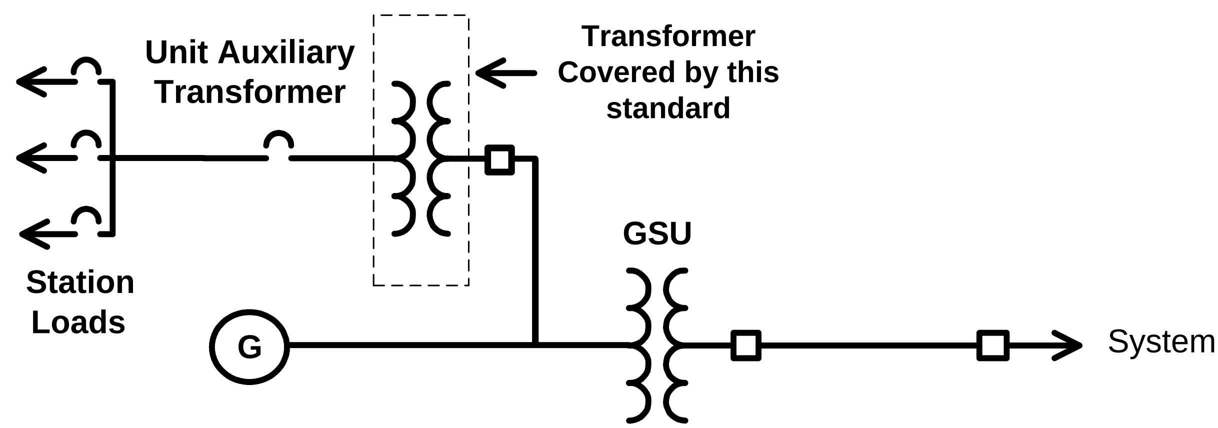


Figure 8: Typical auxiliary power system for generation units or plants

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at

the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$ $pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT high-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8441 \pm 1.1541}{2}$$

$$\left|V_{low-side}\right| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\mathrm{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\mathrm{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\mathrm{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\mathrm{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

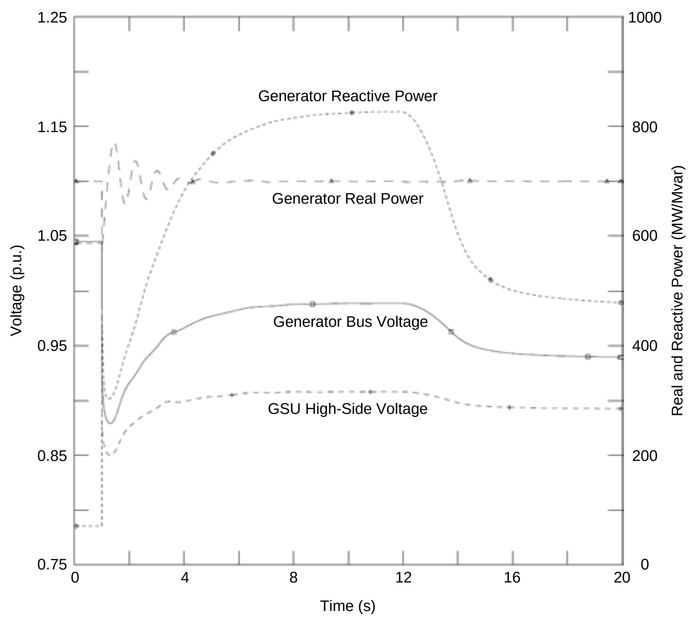
$$Z_{max} < \frac{7.74\,\Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\,\Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Option 2b

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8449 \pm 1.1546}{2}$$

$$\left|V_{low-side}\right| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = \left|V_{low-side}\right| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

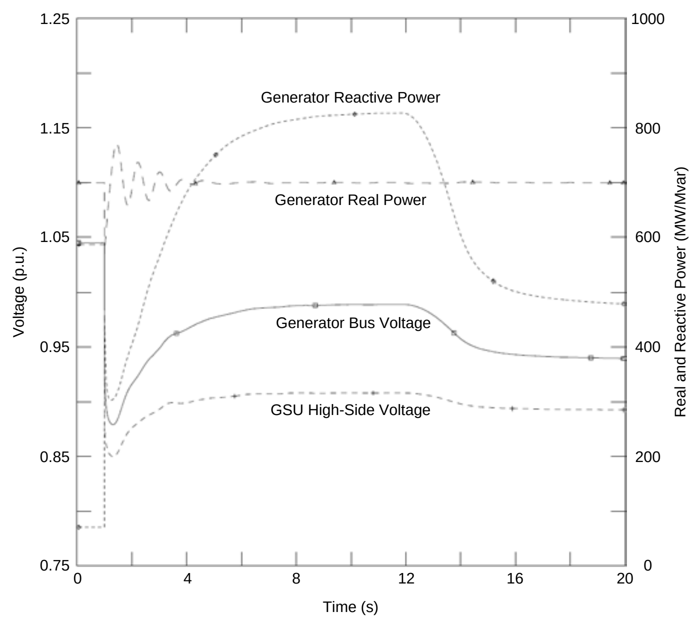
$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV \ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = \ GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA \ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8° \ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8° \ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < \ 77.0\angle 85.0° \ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = \ 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\, p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{gen} = 21.9\, kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\, MW + j83.2\, Mvar$$

$$S = 131.6\angle 39.2°\, MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle - 39.2°\, MVA}{1.73 \times 21.9\, kV}$$

$$I_{pri} = 3473\angle - 39.2°\, A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle - 39.2°\, A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle - 39.2°\, A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle - 39.2°\, A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° \; A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \; MVA \; \times 0.85$$

$$P = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \; Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0 \; p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \; kV \times \left(\frac{22 \; kV}{346.5 \; kV}\right)$$

$$V_{gen} = 21.9 \; kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0 \; MW + j83.2 \; Mvar$$

$$S = 131.6\angle 39.2° \; MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7° \ A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \ MVA \times 0.85$$

$$P_{Asynch} = 102.0 \ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \ Mvar + 5 \ Mvar + (3 \times 40 \ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \ kV \times \left(\frac{22 \ kV}{346.5 \ kV}\right)$$

$$V_{gen} = 20.81 \ kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \ MW + j83.2 \ Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2° \ MVA$$

Primary current ($I_{pri-async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2° \; MVA}{1.73 \times 20.81 \; kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \; A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \; A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \; A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \; A \times 1.00$$

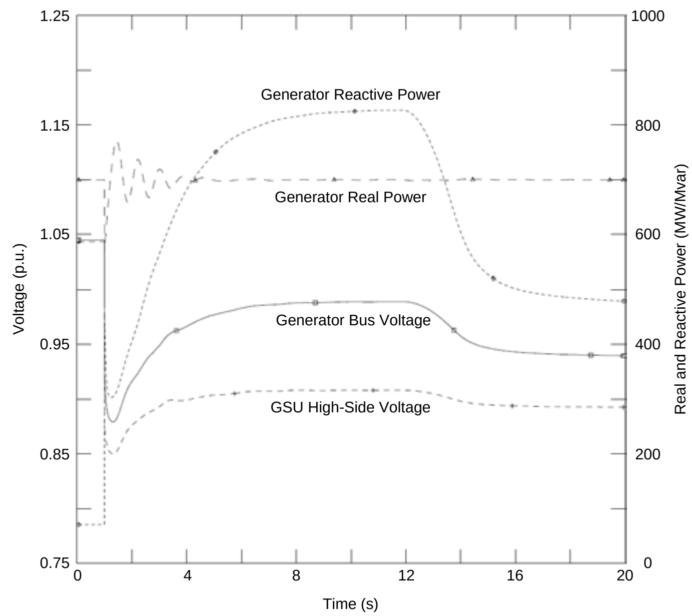
$$I_{\sec limit} > 9.514 \angle -56.8° \; A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle - 39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle - 39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle - 39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

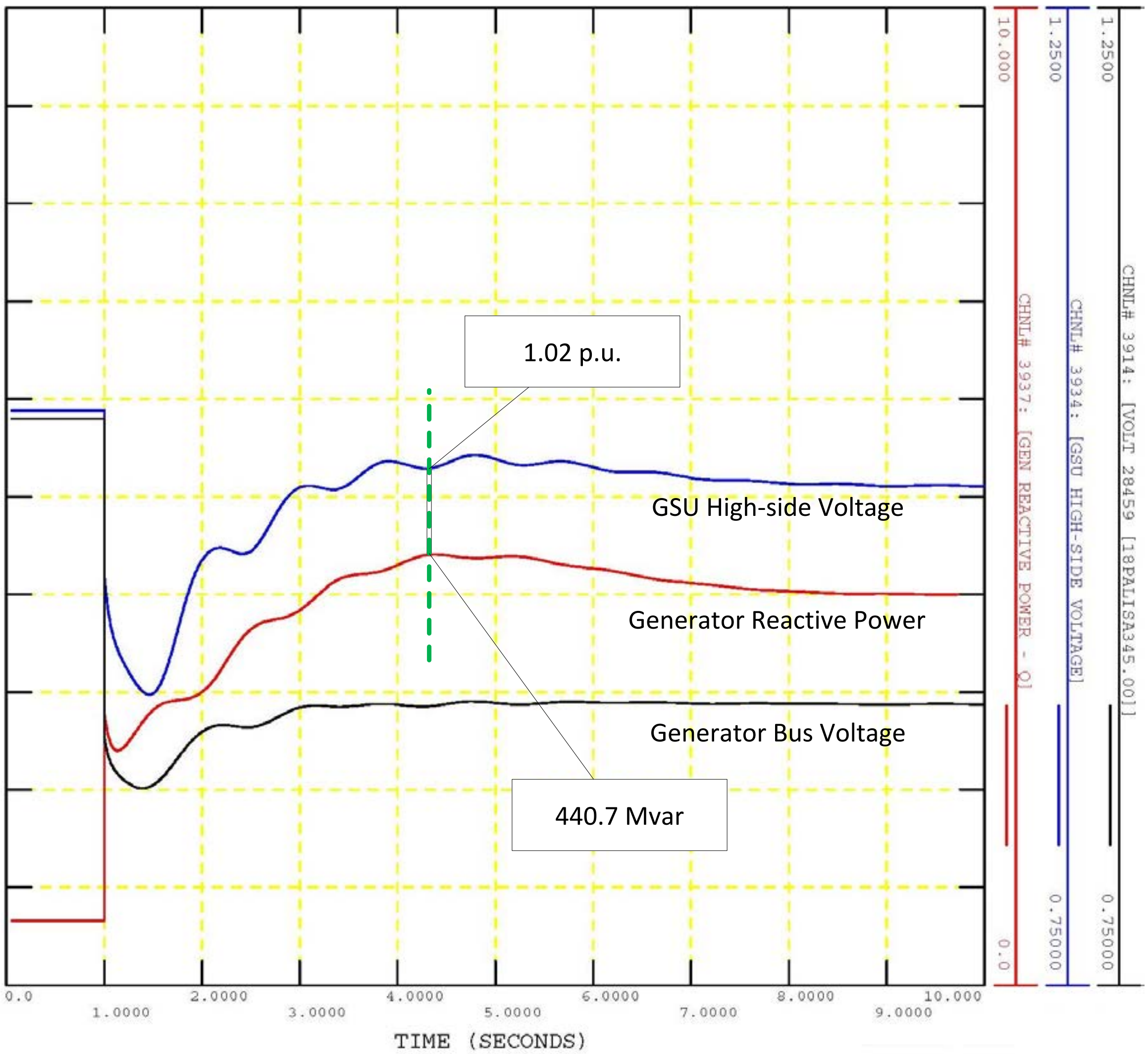
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (152) $S = P_{Synch\_reported} + jQ$

Example Calculations: Option 14b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < \ 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle - 52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle - 52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle - 52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle - 52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

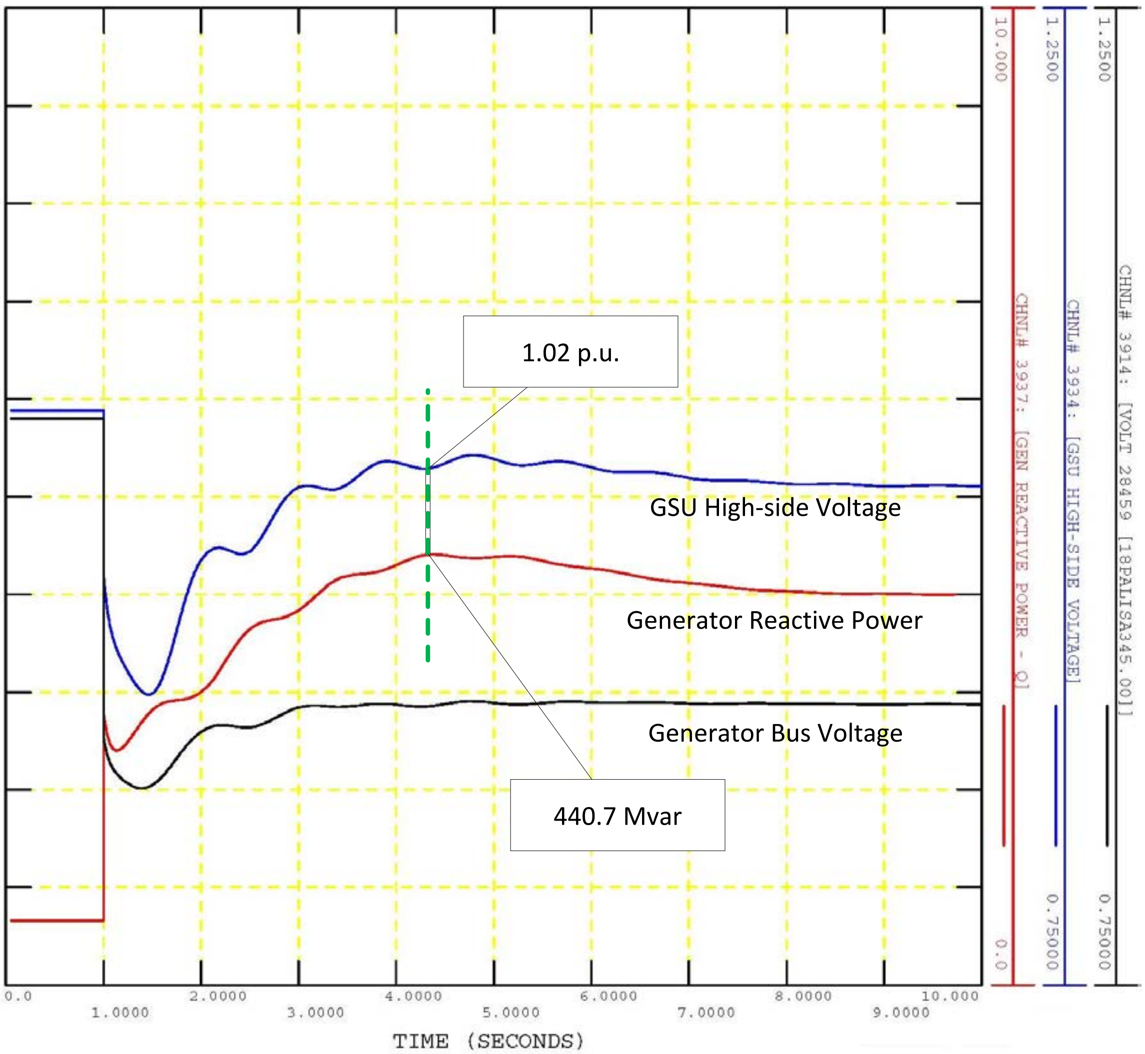
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

Example Calculations: Options 15b and 16b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 3.39\angle -32.2°\ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 3.39\angle -32.2°\ A \times 1.15$$

$$I_{\sec limit} > 3.90\angle -32.2°\ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

Eq. (175) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \ \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

Eq. (176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

Example Calculations: Options 18 and 19

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

PRC-025-2 - Redline Version

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-~~1~~2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~, except that Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

~~6.1. **Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

1. **Compliance Monitoring Process**

~~6.1.~~ **Compliance Enforcement Authority**

1.1. ~~As defined in the NERC Rules of Procedure,~~: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise

[3] ~~Interim Report:~~ Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf~~)~~).

designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention ~~periods~~period(s) 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 Compliance Enforcement Authority ~~(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 ~~Generator Owner, Transmission Owner, and Distribution Provider~~applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~CEA~~Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.

If a Generator Owner, Transmission Owner, or Distribution Provider 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.~~

~~**6.2. Compliance Monitoring and Assessment Processes**~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~**6.3. Additional Compliance Information**~~

~~None~~

~~Table of Compliance Elements~~

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-Term Planning~~	~~High~~	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04
2	February 8, 2018	Adopted by NERC Board of Trustees	Revision

PRC-025-~~1~~2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in ~~3~~4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay~~ pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay~~ pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads~~.),~~), the~~ pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) ~~– installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 15~~	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[7] If the relay is installed on the high-side of the GSU transformer use, Option 15.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

[8] If the relay is installed on the high-side of the GSU transformer use, Option 16.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51)~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.

[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
~~Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)~~	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 19~~[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		

[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
	side terminals of the UAT, for which operation of the relay will cause the associated generator to trip~~.~~	13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system~~ — installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 7~~	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or phase time overcurrent relay (e.g., 51)~~— installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

[13] If the relay is installed on the generator-side of the GSU transformer, use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based,	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[14] If the relay is installed on the generator-side of the GSU transformer, use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant load~~.~~.) –connected to synchronous generators	communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~	16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 10~~	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer, use Option 10.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or Phase time overcurrent relay (e.g., 51)~~— installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 11~~	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or Phase directional time overcurrent relay (e.g., 67)~~—installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 12~~	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

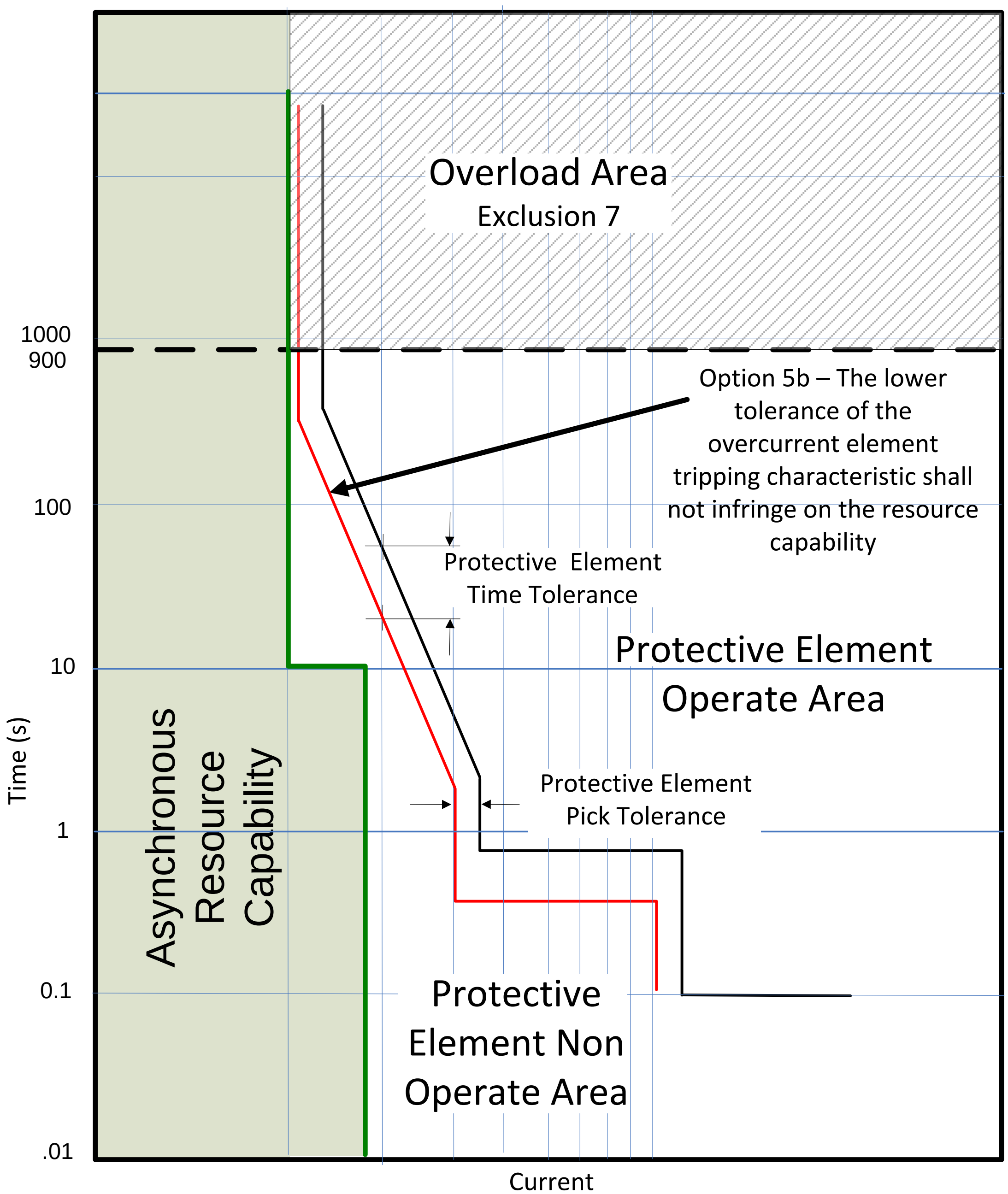


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

~~The document, "Power Plant and Transmission System Protection Coordination,"~~The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed

---

[18] http://www.nerc.com/~~docs/pc/spctf/~~comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20
Gen%20Prot%~~20Coord%20Rev1%20Final%2007-30-2010~~20Coordination%20Technical%20Reference%20Document.pdf.

within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance ~~is~~are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator

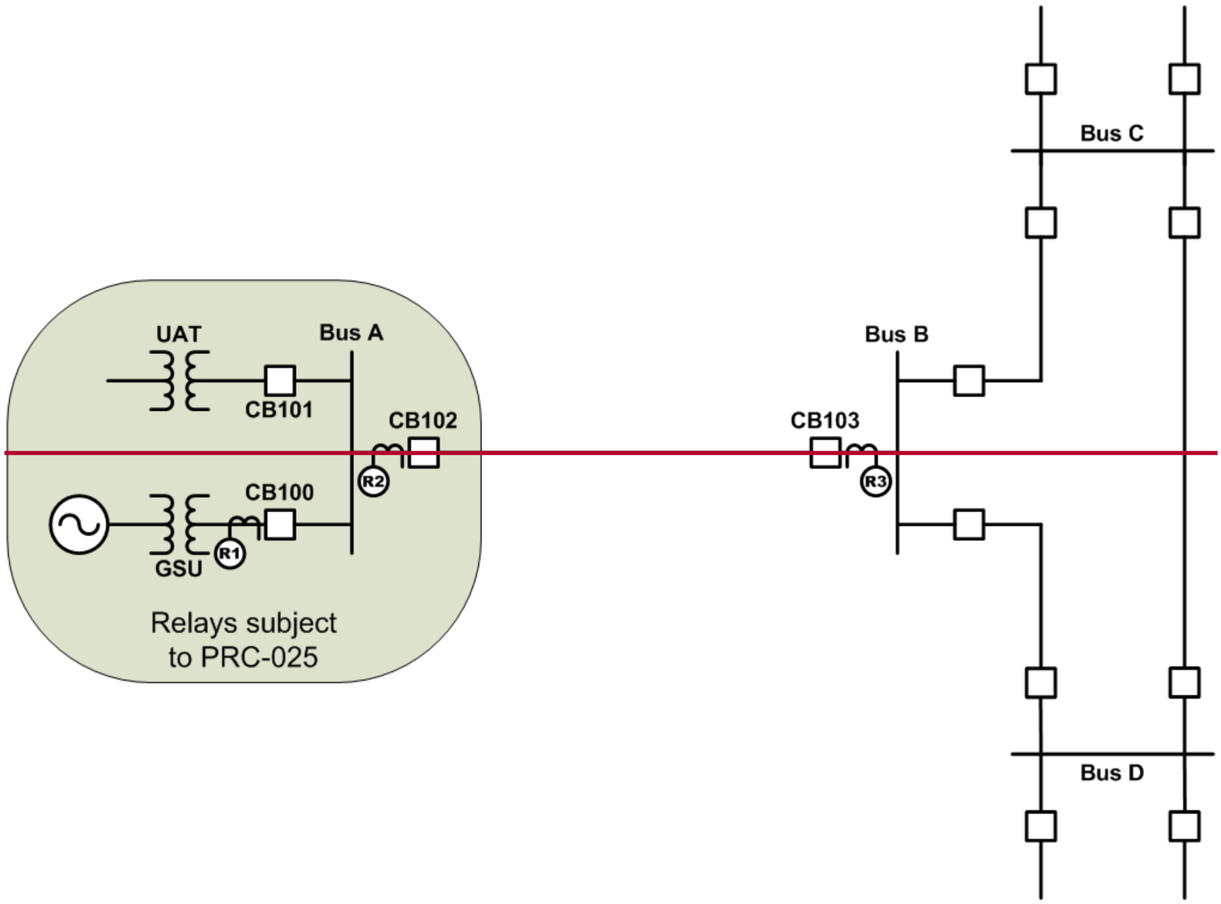
interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case,~~
Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable ~~responsible entity's~~ to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional ~~relay R3 located on breaker CB103 at Bus B looking~~ toward ~~Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not~~the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in ~~this~~the standard~~ or~~. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased ~~transmission system loading~~generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in ~~PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1~~ this standard.~~ PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


Bus C
UAT
Bus A
Bus B
CB101
CB102
CB103
CB100
R2
R3
R1
GSU
Relays subject
to PRC-025
Bus D

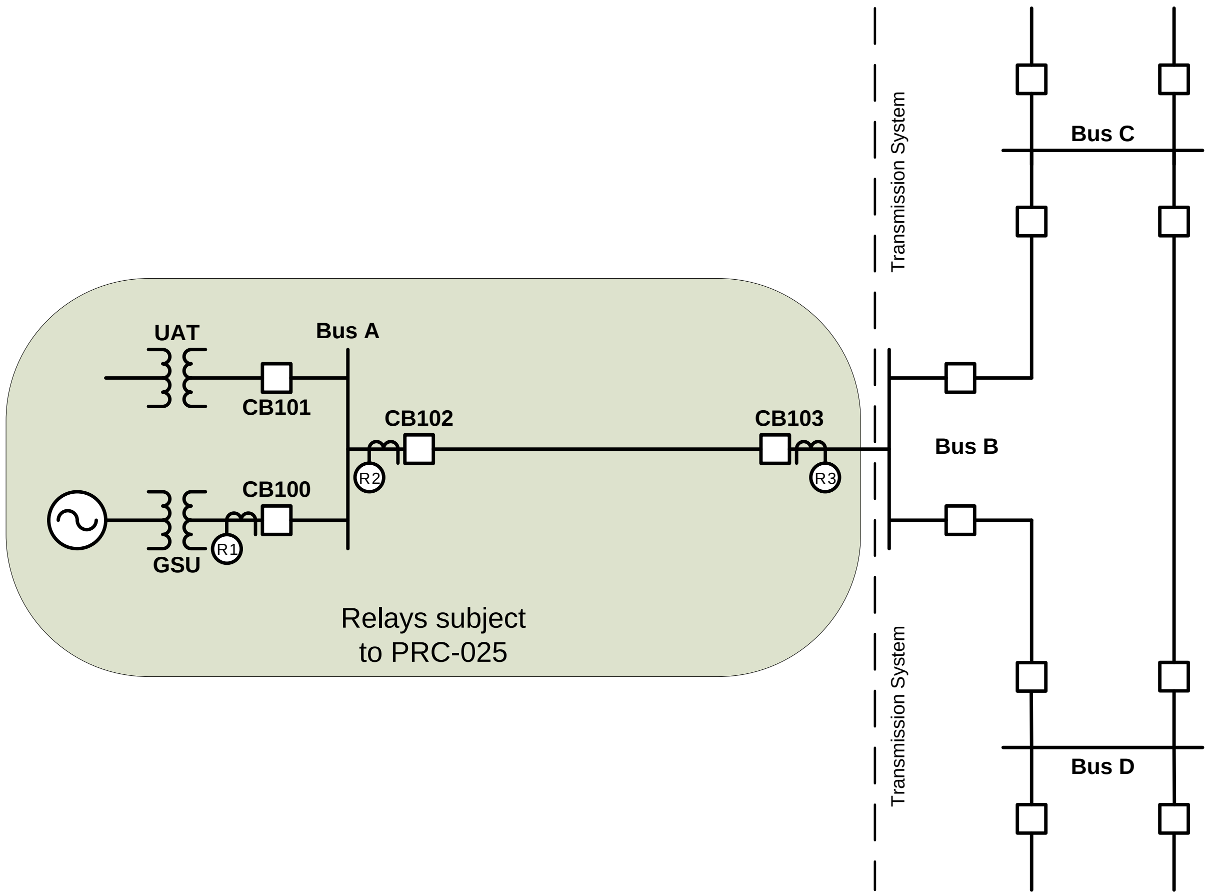


Figure 1~~.~~: Generation exported through a single radial line~~.~~

Figure 2

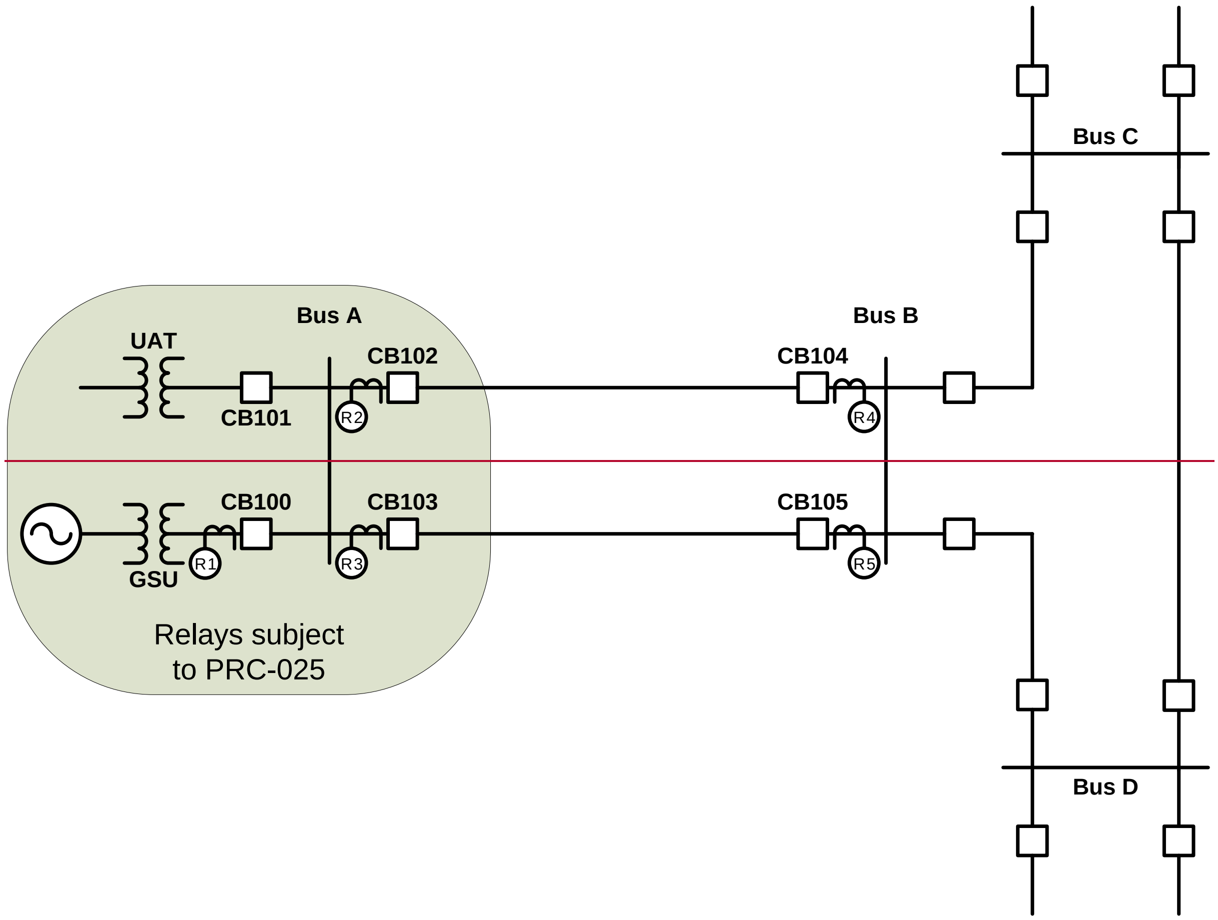
Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.


Bus C
Bus A
Bus B
UAT
CB102
CB104
CB101
R2
R4
CB100
CB103
CB105
R1
R3
R5
GSU
Relays subject
to PRC-025
Bus D

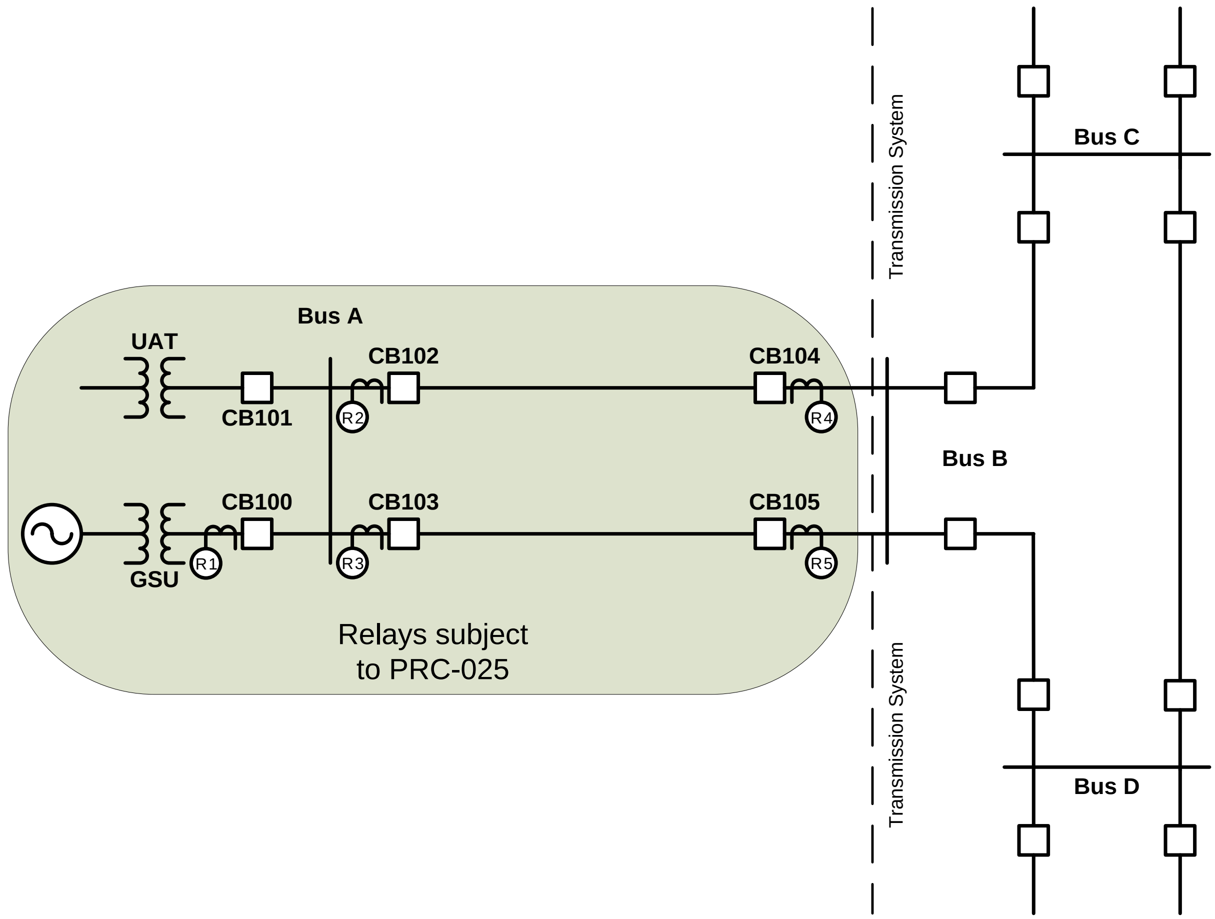
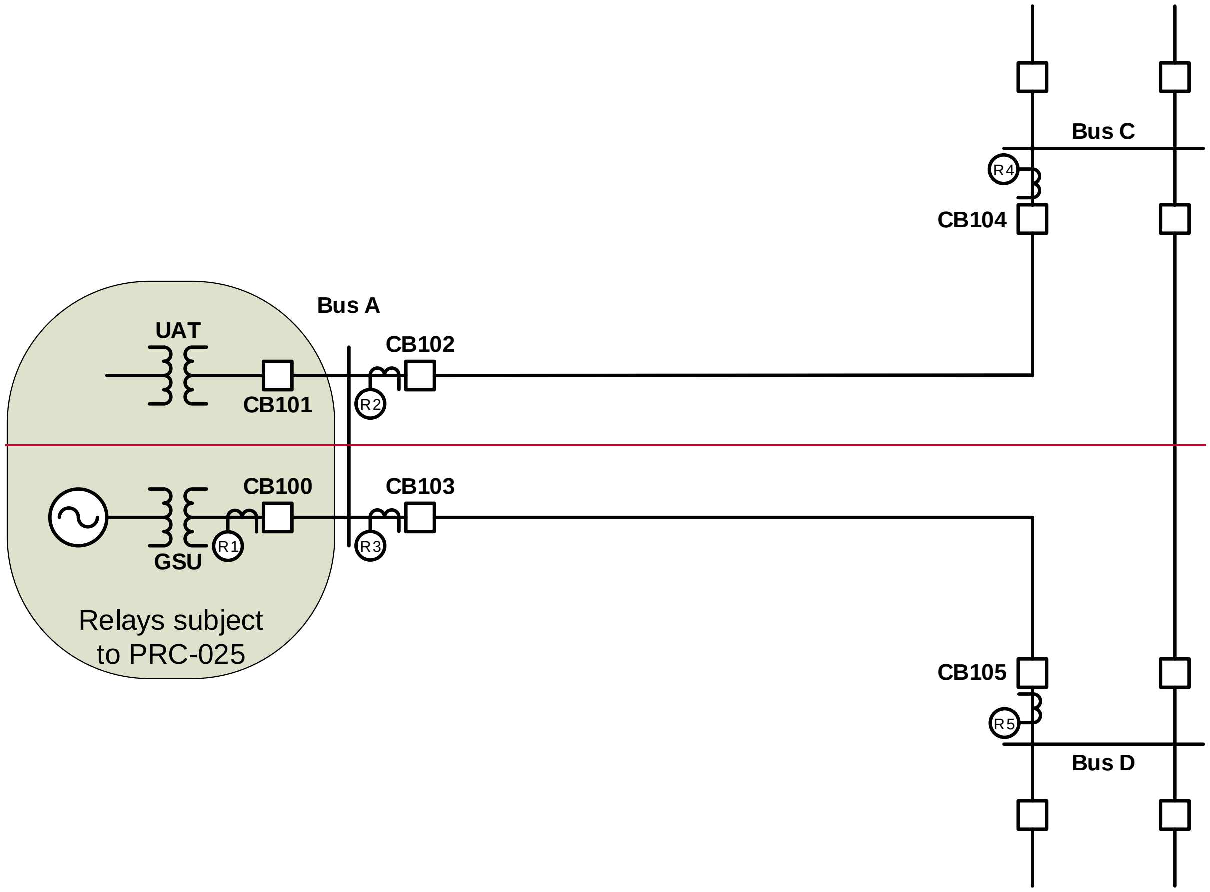


Figure 2~~.~~: Generation exported through multiple radial lines~~.~~

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.


Bus C
R4
CB104
Bus A
UAT
CB102
CB101
R2
CB100
CB103
R1
R3
GSU
Relays subject
to PRC-025
CB105
R5
Bus D

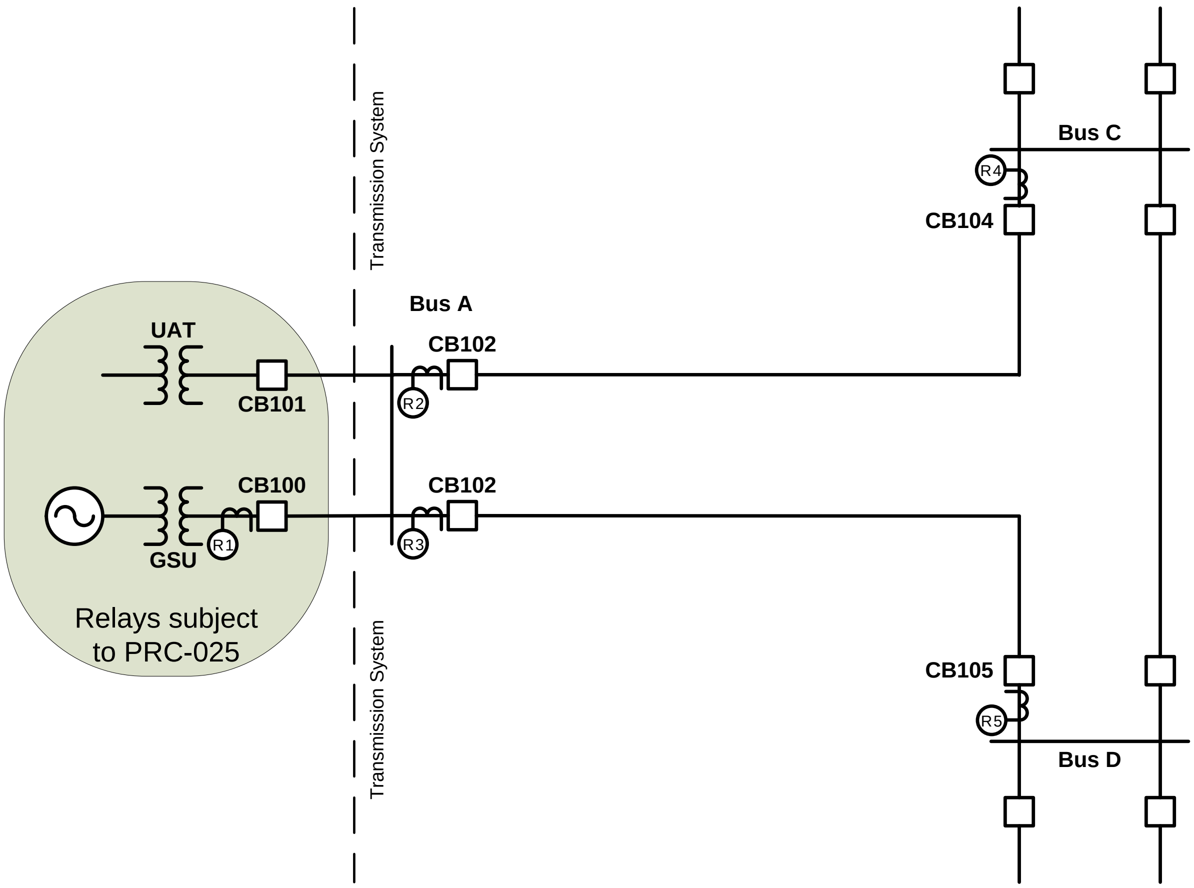


Figure 3~~.~~: Generation exported through a network~~.~~

~~Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.~~

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

---

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

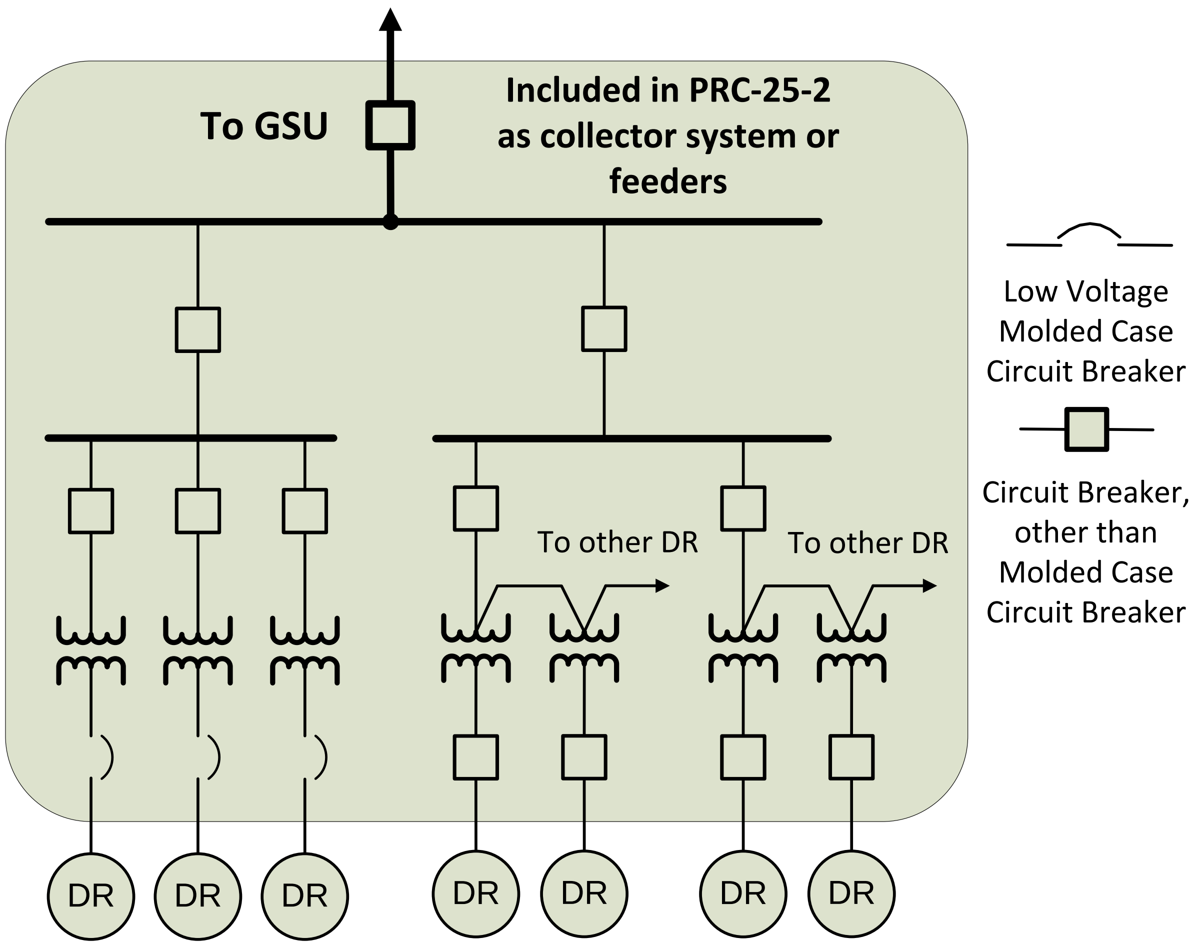


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure ~~5~~6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage ~~to be used~~at the relay location to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still***

> ***protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options differ from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~ setting criteria established within the Table 1 options differ from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

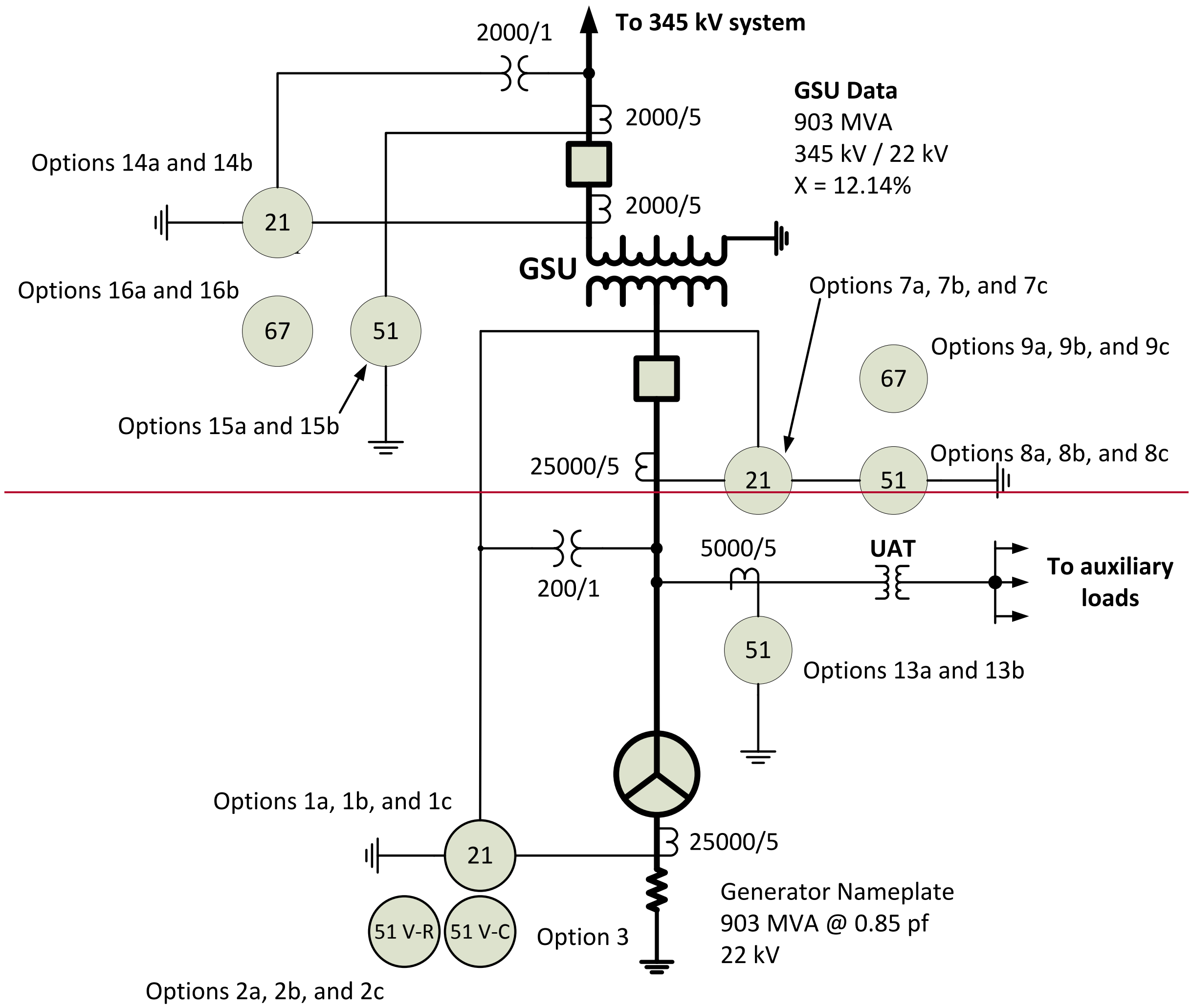
Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures ~~4~~5 and ~~5~~6 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.


To 345 kV system
2000/1
2000/5
GSU Data
903 MVA
345 kV / 22 kV
X = 12.14%
Options 14a and 14b
21
2000/5
GSU
Options 16a and 16b
67
51
Options 7a, 7b, and 7c
Options 9a, 9b, and 9c
67
Options 15a and 15b
25000/5
21
51
Options 8a, 8b, and 8c
200/1
5000/5
UAT
To auxiliary loads
51
Options 13a and 13b
Options 1a, 1b, and 1c
21
25000/5
51 V-R
51 V-C
Option 3
Generator Nameplate
903 MVA @ 0.85 pf
22 kV
Options 2a, 2b, and 2c

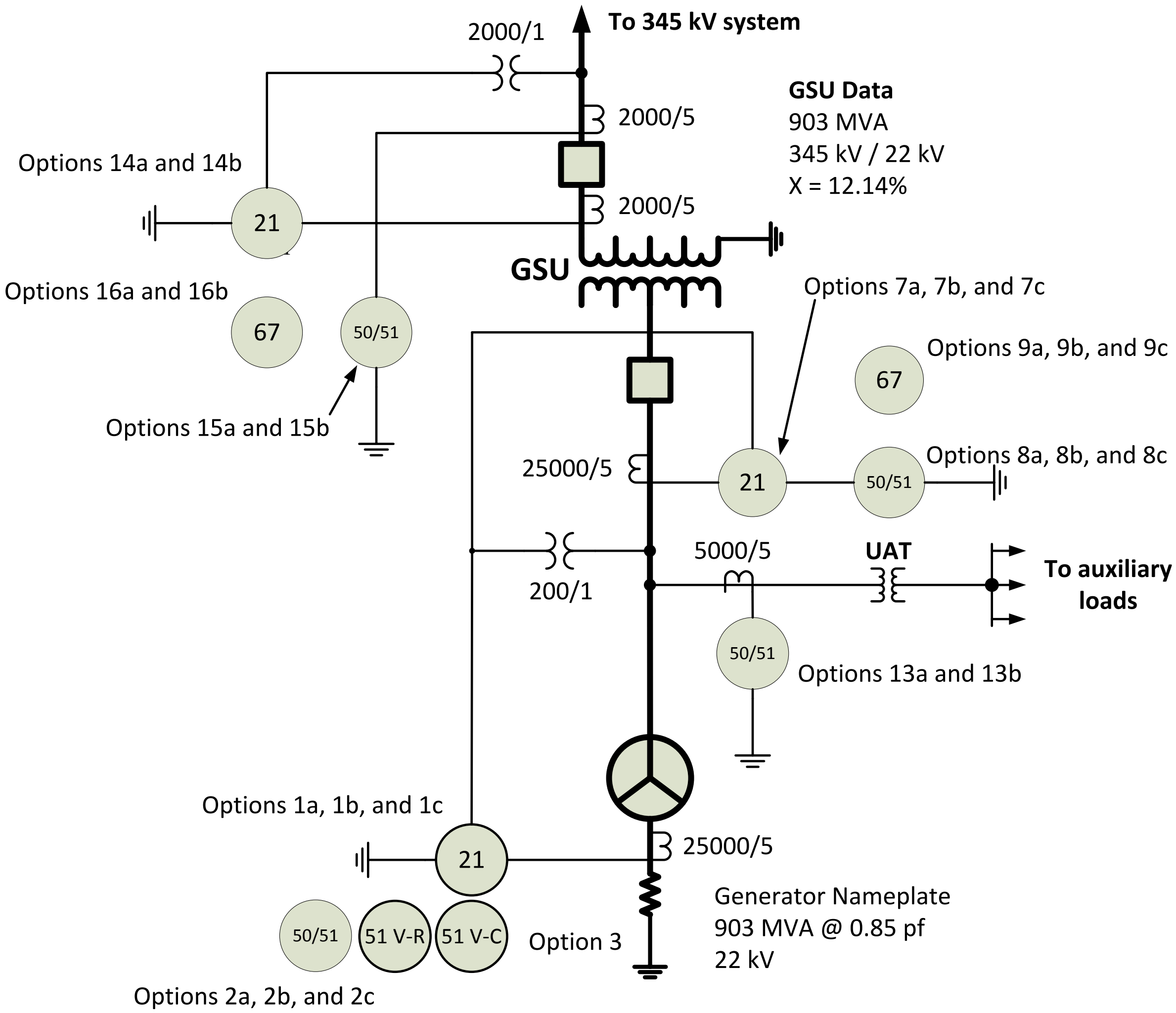
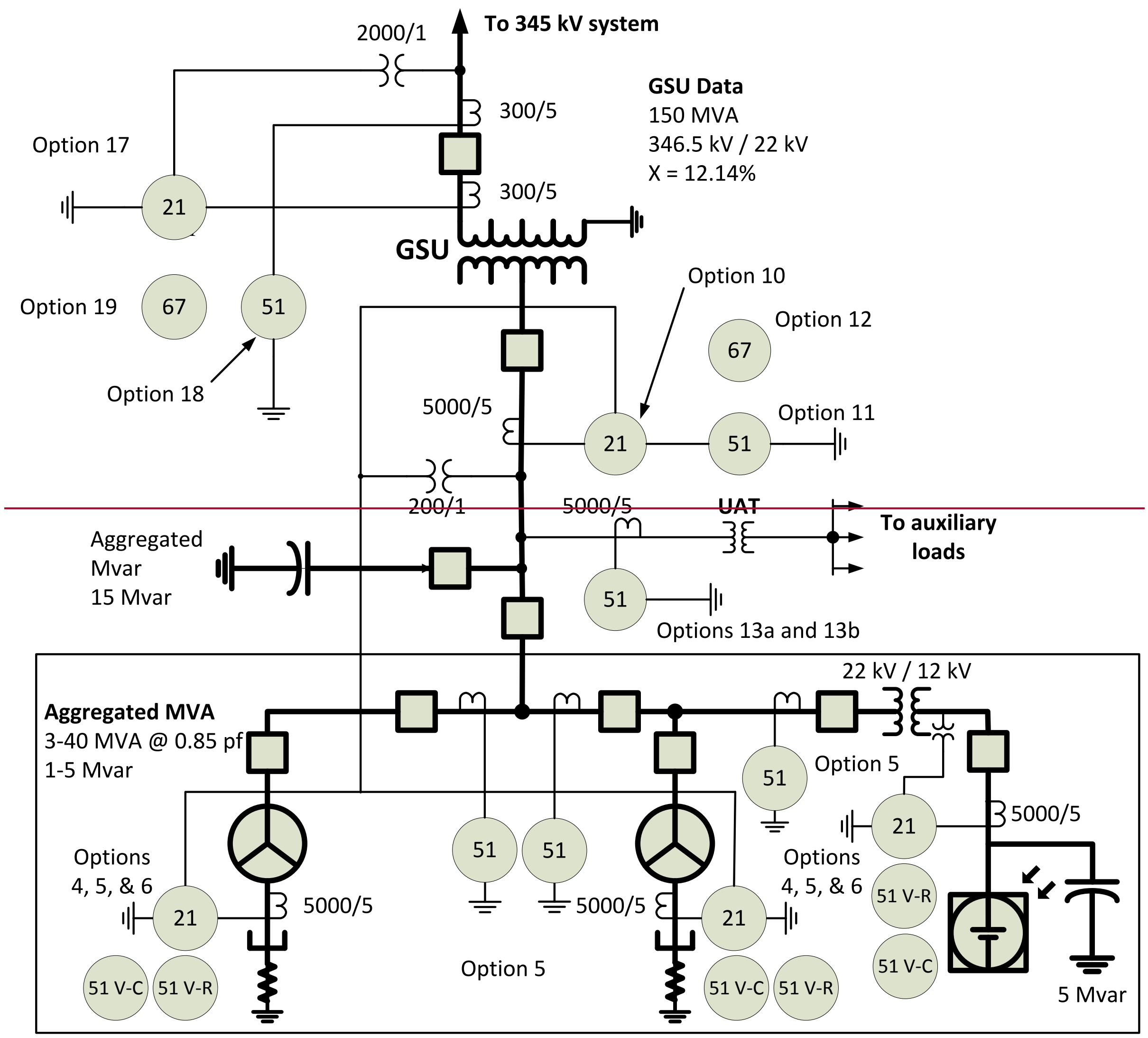


Figure ~~4.~~5: Relay Connection for corresponding synchronous options~~.~~



2000/1
To 345 kV system
300/5
GSU Data
150 MVA
346.5 kV / 22 kV
X = 12.14%
Option 17
21
300/5
GSU
Option 19
67
51
Option 10
Option 12
67
Option 18
5000/5
21
51
Option 11
200/1
5000/5
UAT
To auxiliary loads
Aggregated Mvar 15 Mvar
51
Options 13a and 13b
22 kV / 12 kV
Aggregated MVA
3-40 MVA @ 0.85 pf
1-5 Mvar
51
Option 5
21
5000/5
Options 4, 5, & 6
51
51
Options 4, 5, & 6
51 V-R
21
5000/5
5000/5
21
51 V-C
Option 5
51 V-C
51 V-R
51 V-C
51 V-R
5 Mvar

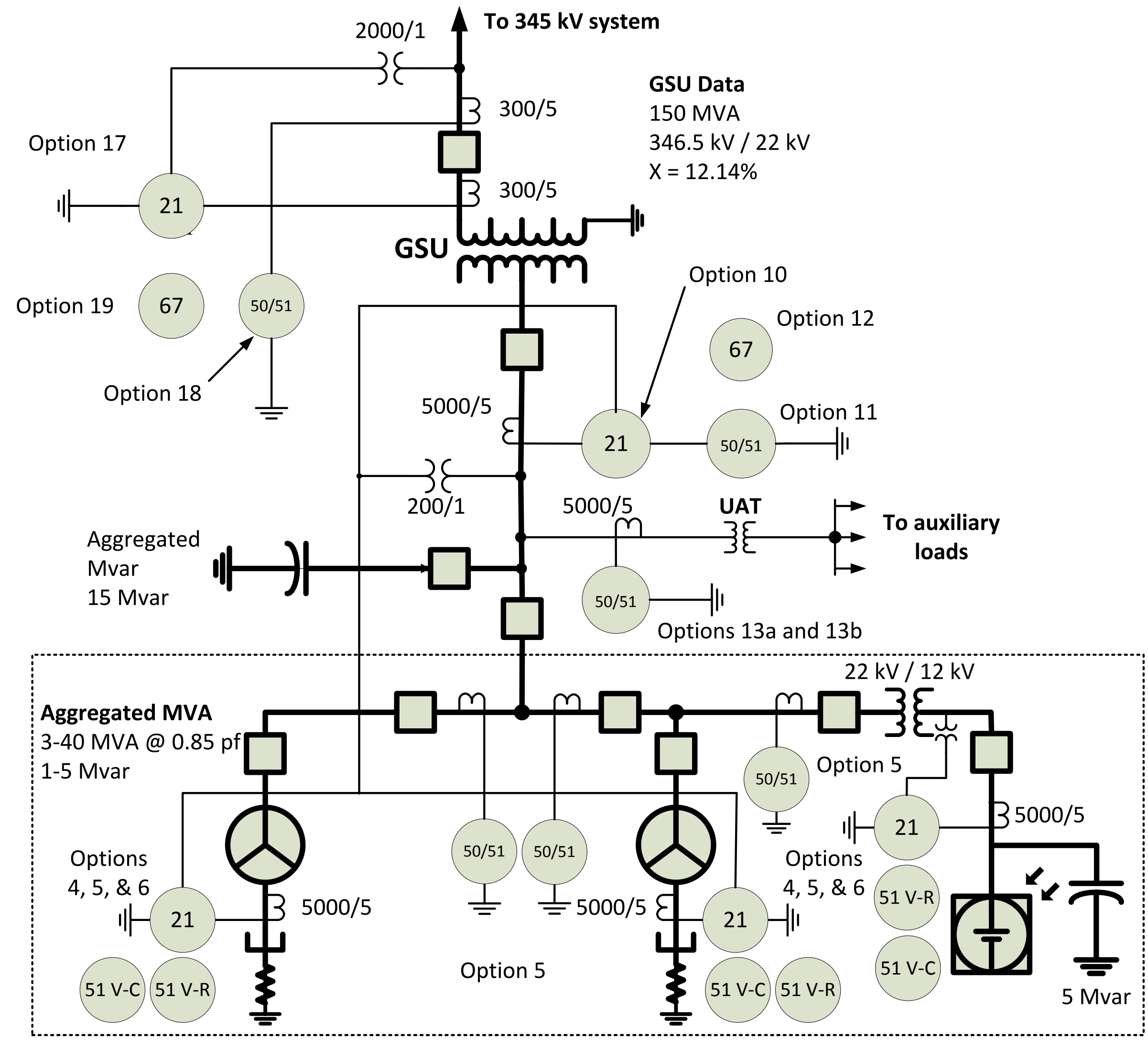


Figure ~~5.~~6: Relay Connection for corresponding asynchronous options including inverter-based installations~~.~~

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times,~~ by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage ~~-~~Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~("voltage~~-restrained~~").~~). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~For Option 4, the impedance element is~~

For Option 5a, the overcurrent element shall be ~~set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

~~Asynchronous Generators Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Option 5)~~

~~Table 1, Option 5 is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which change their sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document.~~

~~Option 5 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

~~For Option 5, the overcurrent element is~~ set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~These margins are based on guidance found in section 3.~~Note that the setting criteria established within the Table 1 ~~of the~~options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options ~~7a, 7b~~8a, 8b, and ~~7c~~8c, are provided for assessing loadability ~~for GSU transformers applying~~of phase ~~distance~~overcurrent relays that are ~~directional toward the Transmission system on synchronous generators that are~~ connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. ~~14.~~

~~Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer.~~ The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer.
~~Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer.~~ The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~ , as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. ~~The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.~~ This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option ~~7a~~8a.

Option ~~7c~~8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~ in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall.~~

~~For~~than Options ~~7a~~8a or 8b.

For Options 8a and ~~7b~~8b, the ~~impedance~~overcurrent element ~~is~~shall be set ~~less~~greater than 115 percent of the calculated ~~impedance~~current derived from ~~115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~both
~~For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of~~: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~Directional Overcurrent Relay ~~(51~~– Directional Toward Transmission System (e.g., 67) (Options ~~8a, 8b~~9a, 9b and ~~8c~~9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options ~~8a, 8b~~9a, 9b, and ~~8c~~9c, are provided for assessing loadability ~~for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.~~

~~Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.~~

~~Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.~~

~~Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~of

~~For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~

~~For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.~~

~~Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability for GSU transformers applying~~ phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.~~ Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than~~

~~establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Option 11 is provided for assessing loadability for GSU transformers applying phase time overcurrent relays on asynchronous generators that are connected to the generator-side of the GSU transformer. Where the relay is connected on the high-side of the GSU transformer, use Option 18.~~

the Table 1 options differ from Chapter 2 of the Considerations for~~Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~

~~Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

~~For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

~~Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the~~ Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option ~~12~~11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers~~ applying~~. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional ~~time~~ overcurrent relays directional toward the Transmission System ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive

Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. ~~This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. ~~Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.~~

Refer to the Figures ~~6~~7 and ~~7~~8 below for example configurations:

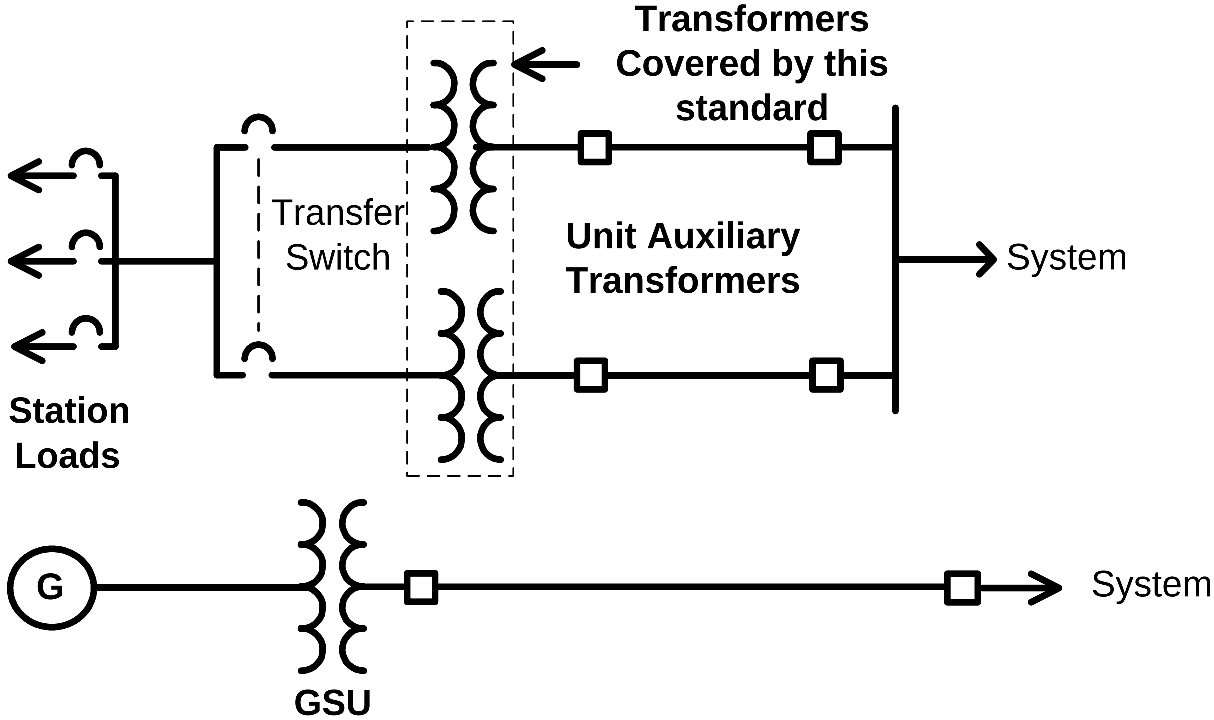


Figure ~~6~~ 7: Auxiliary Power System (independent from generator~~).~~)

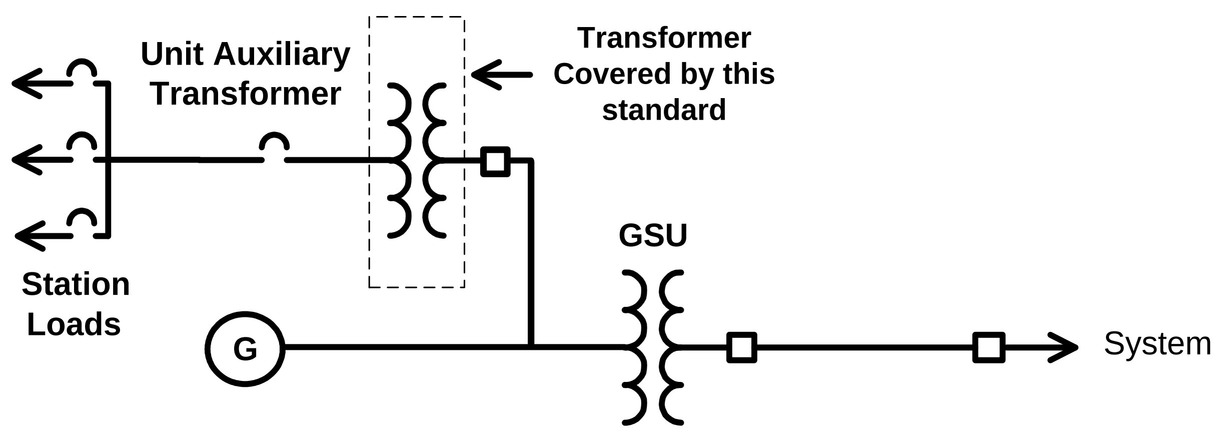


Figure ~~7~~ 8: Typical auxiliary power system for generation units or plants~~.~~

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity’s protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the ~~entity’s~~ relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator’s maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on

Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional~~ time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT high~~low~~-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

~~Eq. (15)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

~~Eq. (17)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle-58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}} \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

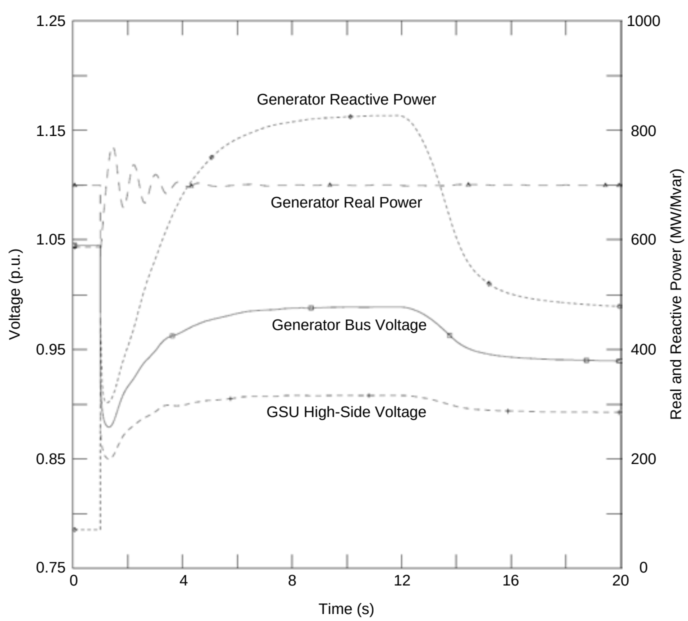
Example Calculations: Options 1c and 7c

~~Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.~~

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~In this simulation the following values are derived:~~



Example Calculations: Options 1c and 7c

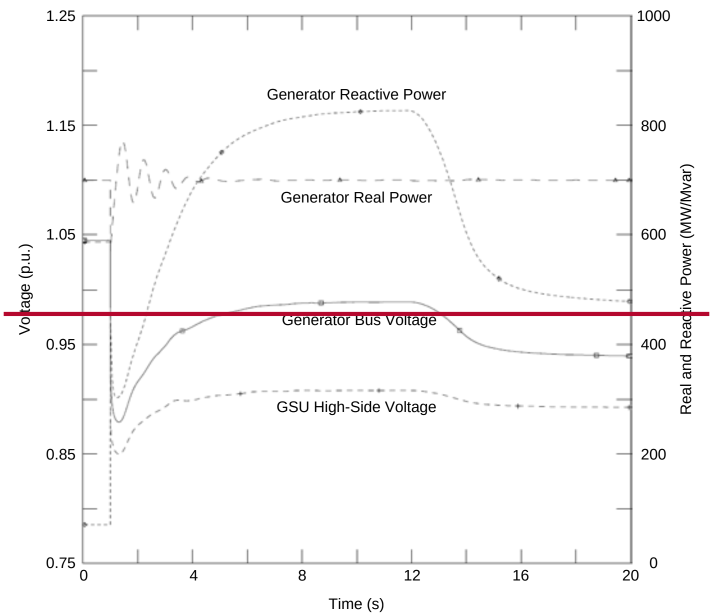
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$\cancel{V_{bus}} V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \cancel{\frac{V_{bus}^2}{S^*}} \frac{V_{bus\_simulated}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

Example Calculations: Options 1c and 7c

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}}\frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7^{\circ}\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

Example Calculations: Option 2a

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7°$$

Eq. (42)

~~Eq. (42)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

~~Eq. (44)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

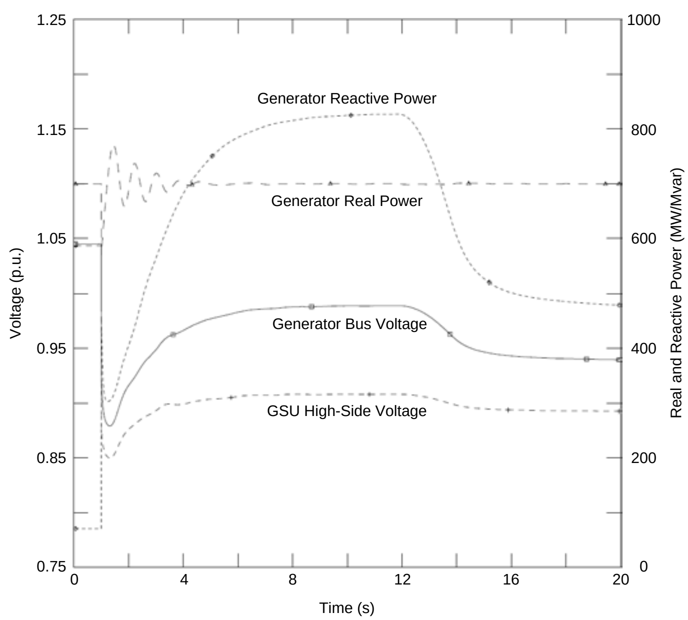
Example Calculations: Option 2b

$$I_{sec\,limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.In this simulation the following values are derived:~~

Example Calculations: Option 2c

In this simulation the following values are derived:

~~$Q = 827.4\ Mvar$~~

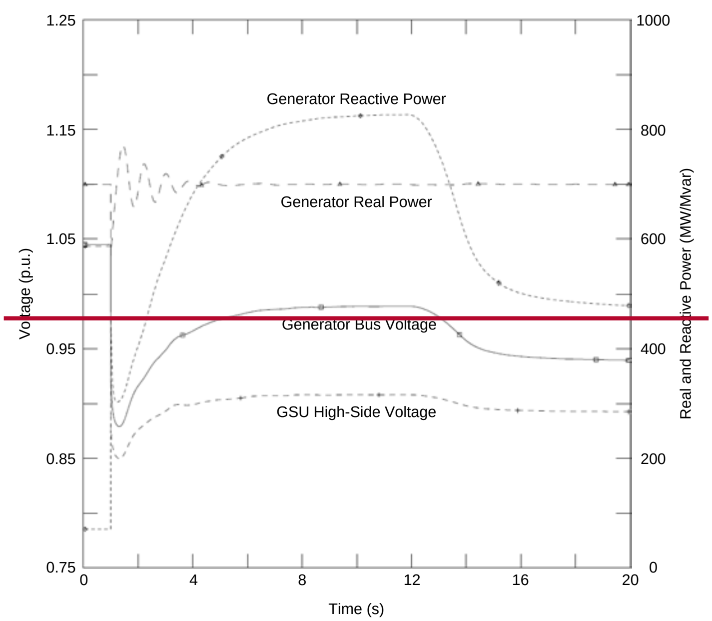
~~$V_{bus} = 0.989 \times V_{gen\_nom} =$~~ $Q = 827.4\ Mvar$ $21.76\ kV$

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:~~

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

~~$P_{Synch\_reported} = 700.0\ MW$~~



$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (50) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Example Calculations: Option 2c

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \cancel{\frac{S}{\sqrt{3} \times V_{bus}}} \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) ~~voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Options 3 and 6

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21)~~–~~ directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Option 4

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $Z_{\sec limit} = \frac{Z_{sec}}{130\%}$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Example Calculations: Option 4

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option ~~5~~5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option ~~5~~5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option ~~5~~5a

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option ~~5~~5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: ~~Options 7a and 10~~Option 5b

~~This~~Similarly to Option 5a, this example represents the calculation for ~~a mixture of~~three asynchronous ~~(i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations)~~generators applying a phase ~~distance~~overcurrent (e.g., 50, 51, or 51V-R) relay ~~(21) directional toward the Transmission system.~~. In this application it was assumed that 20 Mvar of total static compensation was added.

~~**Synchronous Generation (Option 7a)**~~

Real Power output (~~P_{sync}):~~P):

Eq. (71) $\cancel{P_{synch} = GEN_{synch\_nameplate} \times pf} P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: ~~Options 7a and 10~~Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

~~Example Calculations: Options 7a and 10~~

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $Q_{Synch} = 150\% \times P_{Synch}$

$Q_{Synch} = 1.50 \times 767.6\ MW$

$Q_{Synch} = 1151.3\ MW$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$

~~Example Calculations: Options 7a and 10~~

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~84 to satisfy the margin requirements in Options 7a and 10~~:~~.

Eq. (~~81~~87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a ~~represents~~represent the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (~~84~~90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (~~86~~92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~87~~93) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (~~88~~94) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b ~~represents~~represent a more ~~complex~~precise calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (~~90~~96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~91~~97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (~~93~~99)
$$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (~~94~~100)
$$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

~~Eq. (96)~~
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)

$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

~~Eq. (98)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105)

$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Options 8b and 9b

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (~~102~~108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Options 8a, 9a, 11, and 12

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114)
$$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115)
$$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a, 9a, 11, and 12

Apparent power (S_{Asynch}):

Eq. (~~112~~118)
$$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119)
$$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1\ \angle -39.2°\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~114~~120)
$$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061\ \angle -58.7°\ A}{\frac{25000}{5}} + \frac{4755 \angle -39.2°\ A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8°\ A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98.~~118.

Eq. (~~115~~121)
$$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8°\ A \times 1.00$$

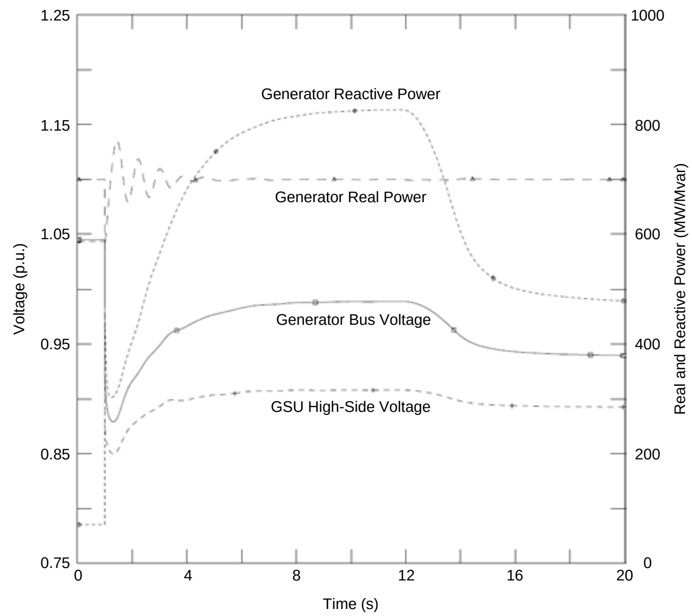
$$I_{\sec limit} > 9.514 \angle -56.8°\ A$$

Example Calculations: Options 8c and 9c

~~This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.~~

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used ~~as~~since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$\cancel{V_{bus}} V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 8c and 9c

Apparent power (S):

Eq. (122) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$$I_{\mathrm{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 10

Real Power output (P):

Eq. (126) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Example Calculations: Option 10

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644 \angle 39.2° \; \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644 \angle 39.2° \; \Omega \times 5$$

$$Z_{sec} = 18.22 \angle 39.2° \; \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22 \angle 39.2° \; \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02 \angle 39.2° \; \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02 \; \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02 \; \Omega}{0.6972}$$

$$Z_{max} < 20.11 \angle 85.0° \; \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 11 and 12

$$I_{pri} = \frac{131.6\angle-39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle-39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle-39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle-39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle-39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle-39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Example Calculations: Options 13a and 13b

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \mathrm{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

Example Calculations: Option 14a

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

Example Calculations: Option 14a

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

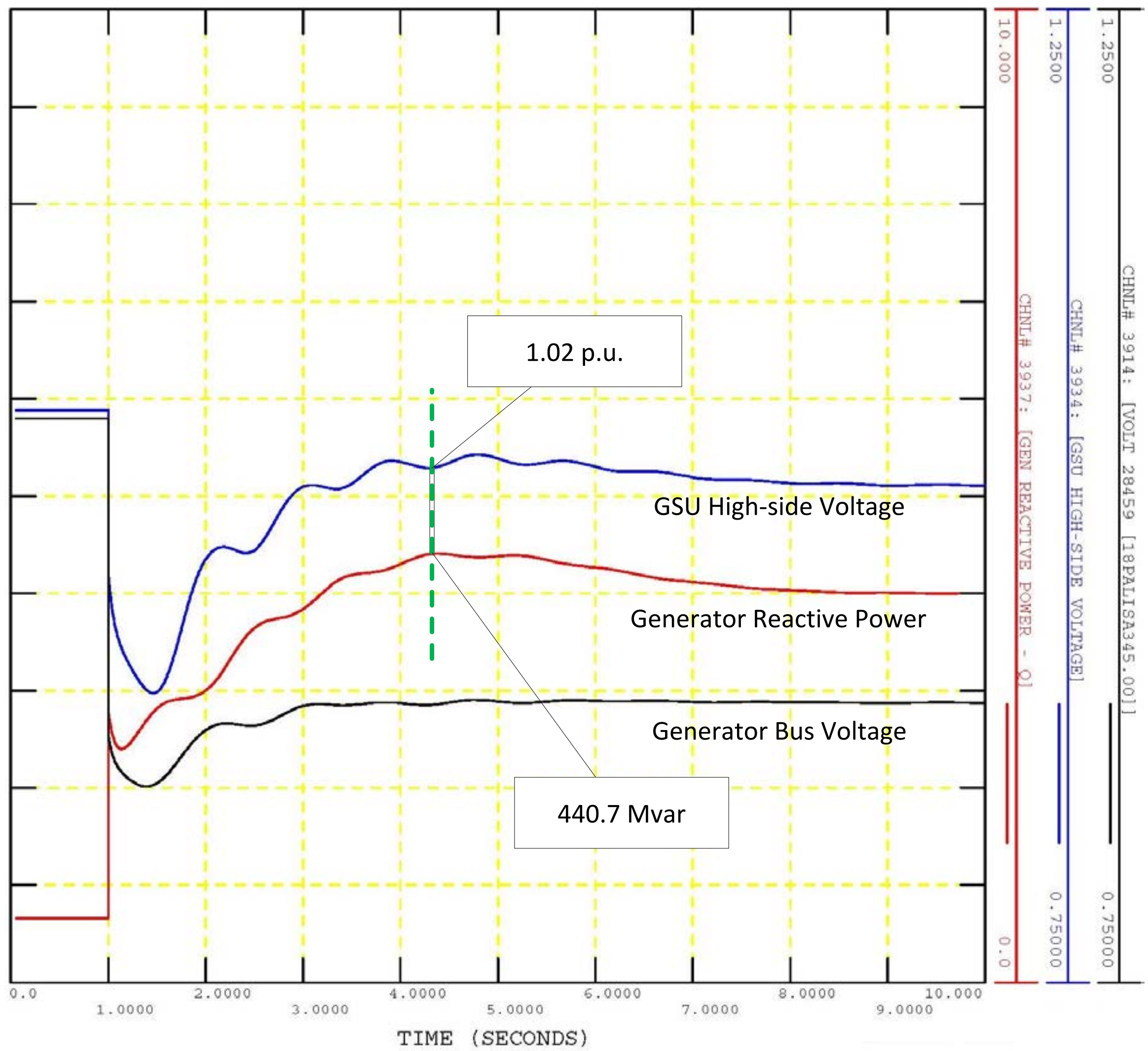
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

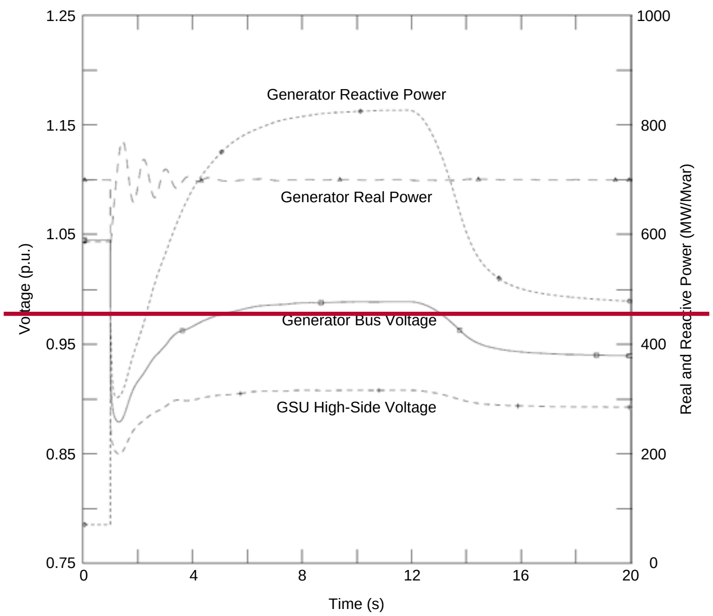
$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Option 14b



Apparent power (S):

Eq. (~~116~~152) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + \cancel{j827.4}\,j440.7\ Mvar$$

$$S = \cancel{1083.8\angle 49.8°}\,827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary ~~current (I~~~~pri~~impedance (Z~~pri~~)):

Eq. (~~117~~153) $\cancel{I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}}\,Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$

$$\cancel{I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}}\,Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$\cancel{I_{pri} = 28790\ A}\,Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary ~~current (I~~~~sec~~impedance (Z~~sec~~)):

Eq. (~~118~~154) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}\,\cancel{I_{sec} = \frac{I_{pri}}{CT_{ratio}}}$

Example Calculations: Option 14b

$$\cancel{I_{sec} = \frac{28790\ A}{\frac{25000}{5}}} Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$\cancel{I_{sec} = 5.758\ A} Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in ~~Options 8c and 9c~~Option 14b:

Eq. (~~119~~155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%} \cancel{I_{\sec limit} > I_{sec} \times 115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

~~Example Calculations: Options 15a and 16a~~

$$\cancel{I_{\sec limit} > 5.758\ A \times 1.15}$$

$$\cancel{I_{\sec limit} > 6.622\ A}$$

~~Example Calculations: Option10~~

~~This represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.~~

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

~~Eq. (120)~~ $\cancel{P = 3 \times GEN_{Asych\_nameplate} \times pf}$

$$\cancel{P = 3 \times 40\ MVA \times 0.85}$$

$$\cancel{P = 102.0\ MW}$$

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

~~Example Calculations: Option10~~

Reactive Power output (Q):

Eq. (158) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

~~Eq. (121)~~ $$\cancel{Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)}$$

$$\cancel{Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))}$$

$$\cancel{Q = 83.2\ Mvar}$$

~~Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):~~

~~Eq. (122)~~ $$\cancel{V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}}$$

$$\cancel{V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)}$$

$$\cancel{V_{gen} = 21.9\ kV}$$

Apparent power (S):

~~Eq. (123)~~ $$\cancel{S = P + jQ}$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

~~Primary impedance (Z_{pri}):~~

~~Eq. (124)~~ $$\cancel{Z_{pri} = \frac{V_{gen}^2}{S^*}}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

~~**Example Calculations: Option10**~~

$$Z_{pri} = 3.644 \angle 39.2° \, \Omega$$

~~Secondary impedance (Z_{sec}):~~

~~Eq. (125)~~ $$\cancel{Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}}$$

$$\cancel{Z_{sec} = 3.644 \angle 39.2° \, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}}$$

$$\cancel{Z_{sec} = 3.644 \angle 39.2° \, \Omega \times 5}$$

$$\cancel{Z_{sec} = 18.22 \angle 39.2° \, \Omega}$$

~~To satisfy the 130% margin in Option 10:~~

~~Eq. (126)~~ $$\cancel{Z_{sec\,limit} = \frac{Z_{sec}}{130\%}}$$

$$\cancel{Z_{sec\,limit} = \frac{18.22 \angle 39.2° \, \Omega}{1.30}}$$

$$\cancel{Z_{sec\,limit} = 14.02 \angle 39.2° \, \Omega}$$

$$\cancel{\theta_{transient\ load\ angle} = 39.2°}$$

~~Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:~~

~~Eq. (127)~~ $$\cancel{Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$$

$$Z_{max} < \frac{14.02 \, \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02 \, \Omega}{0.6972}$$

$$Z_{max} < 20.11 \angle 85.0° \, \Omega$$

Eq. (160) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \, MW + j921.12 \, Mvar$$

$$S = 1157 \angle 52.8° \, MVA$$

~~Example Calculations: Options 11 and 12~~

~~Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.~~

~~Real Power output (P):~~

~~Eq. (128)~~ $\cancel{P = 3 \times GEN_{Asynch\_nameplate} \times pf}$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

~~Reactive Power output (Q):~~

~~Eq. (129)~~ $\cancel{Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)}$

$$\cancel{Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))}$$

$$\cancel{Q = 83.2\ Mvar}$$

~~Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):~~

~~Eq. (130)~~ $\cancel{V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}}$

$$\cancel{V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)}$$

$$\cancel{V_{gen} = 21.9\ kV}$$

~~Apparent power (S):~~

~~Eq. (131)~~ $\cancel{S = P + jQ}$

$$\cancel{S = 102.0\ MW + j83.2\ Mvar}$$

$$\cancel{S = 131.6\ \angle 39.2°\ MVA}$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

~~Eq. (132)~~ $\cancel{I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}}$

$\cancel{I_{pri} = \frac{131.6\angle -39.2° \, MVA}{1.73 \times 21.9 \, kV}}$

$\cancel{I_{pri} = 3473\angle -39.2° \, A}$

Secondary current (I_{sec}):

~~Eq. (133)~~ $\cancel{I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}}$

$$I_{sec} = \frac{3473\angle -39.2° \, A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2° \, A$$

~~To satisfy the 130% margin in Options 11 and12:~~

~~Eq. (134)~~ $\cancel{I_{sec\,limit} > I_{sec} \times 130\%}$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2° \, A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.515\angle -39.2° \, A$$

~~Example Calculations: Options 13a and 13b~~

~~Option 13a for the UAT assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.~~

~~Primary current (I_{pri}):~~

~~Eq. (135)~~ $\cancel{I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}}$

$\cancel{I_{pri} = \frac{60 \, MVA}{1.73 \times 13.8 \, kV}}$

$\cancel{I_{pri} = 2510.2 \, A}$

~~Secondary current (I_{sec}):~~

~~Eq. (136)~~ $\cancel{I_{sec} = \frac{I_{pri}}{CT_{UAT}}}$

~~Example Calculations: Options 13a and 13b~~

$$\cancel{I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}}$$

$$\cancel{I_{sec} = 2.51\ A}$$

~~To satisfy the 150% margin in Options 13a:~~

~~Eq. (137)~~ $\cancel{I_{sec\,limit} > I_{sec} \times 150\%}$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\ A$$

~~Example Calculations: Option 14a~~

~~Option 14a represents the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.~~

Calculations at the remote end of the line from the plant.

Real Power output (P):

~~Eq. (138)~~ $\cancel{P = GEN_{Synch\_nameplate} \times pf}$

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

~~Eq. (139)~~ $\cancel{Q = 120\% \times P}$

Eq. (165) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$\cancel{Q = 921.1\ Mvar}$

~~Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):~~

~~Eq. (140)~~ $\cancel{V_{bus} = 0.85\ p.u. \times V_{nom}}$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $V_{bus\_remote\_substation} = 0.85\ p.u. \times V_{nom}$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

$$V_{bus\_remote\_substation} = 293.25\ kV$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8^\circ\ MVA$$

Primary current (I_{pri}):

Eq. (168) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$

$$I_{pri} = \frac{1157\angle -52.8^{\circ}\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8^{\circ}\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8^{\circ}\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8^{\circ}\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8^{\circ}\ A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8^{\circ}\ A$$

~~Example Calculations: Options 15b and 16b~~

~~Eq. (141)~~ $\cancel{S = P_{synch\_reported} + jQ}$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

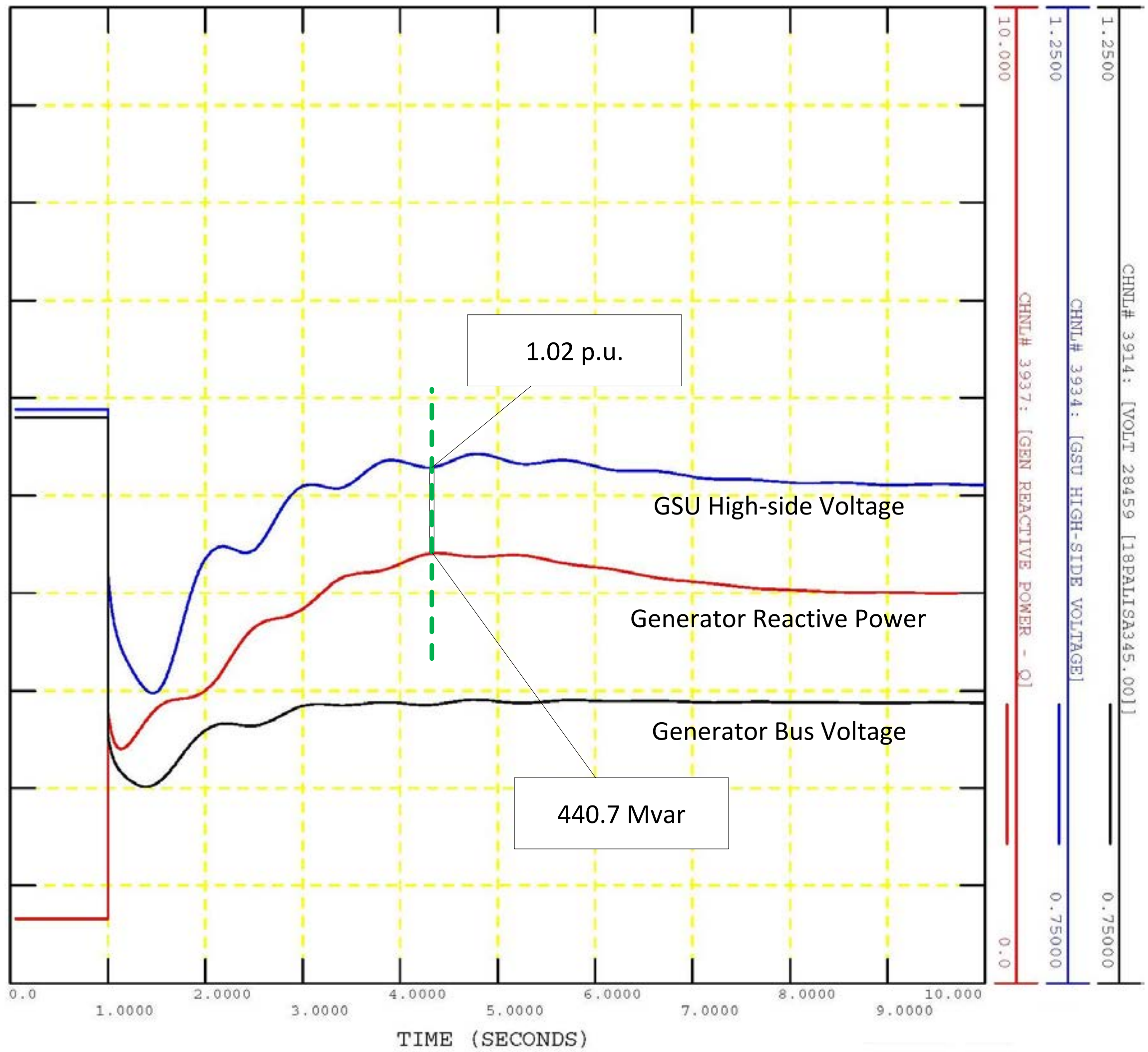
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

~~Example Calculations: Options 15b and 16b~~

~~Primary impedance (Z_{pri}):~~

Eq. (142) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

~~Secondary impedance (Z_{sec}):~~

Eq. (143) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

~~To satisfy the 115% margin in Option 14a:~~

Eq. (144) $$Z_{sec\ limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\ limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{sec\ limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

~~Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:~~

Eq. (145) $$Z_{max} < \frac{|Z_{sec\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

~~Example Calculations: Option 14b~~

~~Option 14b represents the simulation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.~~

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

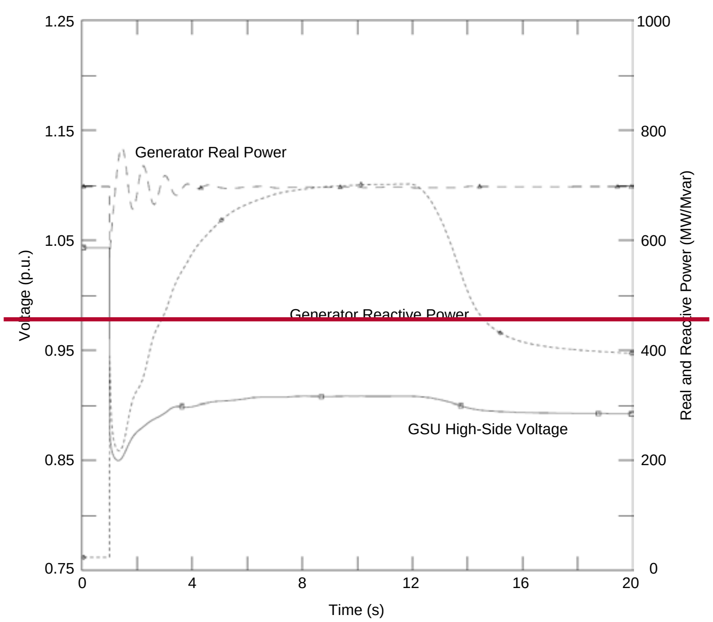
~~In this simulation the following values are derived:~~

$$\cancel{Q = 703.6\ Mvar}$$

$$\cancel{V_{bus} = 0.908 \times V_{nom} = 313.3\ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~171) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + \cancel{j703.6}\, j440.7\ Mvar$$

~~Example Calculations: Option 14b~~

$$S = \cancel{992.5\angle 45.1}\, 827.2\angle 32.2°\ MVA$$

~~$\theta_{transient\ load\ angle} = 45.1°$~~

Primary ~~impedance (Z~~~~pri~~current (I_{pri}):

Eq. (~~147~~172) ~~$Z_{pri} = \frac{V_{bus}^2}{S^*}$~~ $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$

~~$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$~~ $I_{pri} = \dfrac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$

~~$Z_{pri} = 98.90\angle 45.1°\ \Omega$~~ $I_{pri} = 1357.1\angle -32.2°\ A$

Secondary ~~impedance (Z~~~~sec~~current (I_{sec}):

Eq. (~~148~~173) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio\_hv}}$ ~~$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$~~

~~$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$~~ $I_{sec} = \dfrac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$

~~$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$~~ $I_{sec} = 3.39\angle -32.2°\ A$

~~$Z_{sec} = 19.78\angle 45.1°\ \Omega$~~

To satisfy the 115% margin in ~~Option 14b~~Options 15b and 16b:

Eq. (~~149~~174) $I_{sec\,limit} > I_{sec} \times 115\%$ ~~$Z_{sec\,limit} = \frac{Z_{sec}}{115\%}$~~

~~$Z_{sec\,limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$~~

~~$Z_{sec\,limit} = 17.20\angle 45.1°\ \Omega$~~ $I_{sec\,limit} > 3.39\angle -32.2°\ A \times 1.15$

~~$\theta_{transient\ load\ angle} = 45.1°$~~ $I_{sec\,limit} > 3.90\angle -32.2°\ A$

~~Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:~~

~~Eq. (150)~~ ~~$Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$~~

~~$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$~~

~~Example Calculations: Option 14b~~

$$\cancel{Z_{max} < \frac{17.20\ \Omega}{0.767}}$$

$$\cancel{Z_{max} < 22.42\angle 85.0°\ \Omega}$$

~~Example Calculations: Options 15a and 16a~~

~~Options 15a and 16a represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15a represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.~~

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~

~~Real Power output (P):~~

~~Eq. (151)~~ $\cancel{P = GEN_{synch\_nameplate} \times pf}$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

~~Reactive Power output (Q):~~

~~Eq. (152)~~ $\cancel{Q = 120\% \times P}$

$$\cancel{Q = 1.20 \times 767.6\ MW}$$

$$\cancel{Q = 921.12\ Mvar}$$

~~Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:~~

~~Eq. (153)~~ $\cancel{V_{bus} = 0.85\ p.u. \times V_{nom}}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

~~Apparent power (S):~~

~~Eq. (154)~~ $\cancel{S = P_{synch\_reported} + jQ}$

~~Example Calculations: Options 15a and 16a~~

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

~~Primary current (I_{pri}):~~

~~Eq. (155)~~ $$\cancel{I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}}$$

$$I_{pri} = \frac{1157\angle - 52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle - 52.8°\ A$$

~~Secondary current (I_{sec}):~~

~~Eq. (156)~~ $$\cancel{I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}}$$

$$\cancel{I_{sec} = \frac{2280.6\angle - 52.8°\ A}{\frac{2000}{5}}}$$

$$\cancel{I_{sec} = 5.701\angle - 52.8°\ A}$$

~~To satisfy the 115% margin in Options 15a and 15b:~~

~~Eq. (157)~~ $$\cancel{I_{sec\,limit} > I_{sec} \times 115\%}$$

$$I_{\text{sec}\,limit} > 5.701\angle - 52.8°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56\angle - 52.8°\ A$$

~~Example Calculations: Options 15b and 16b~~

~~Options 15b and 16b represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15b represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system – installed on the high-side of the GSU.~~

~~This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.~~

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

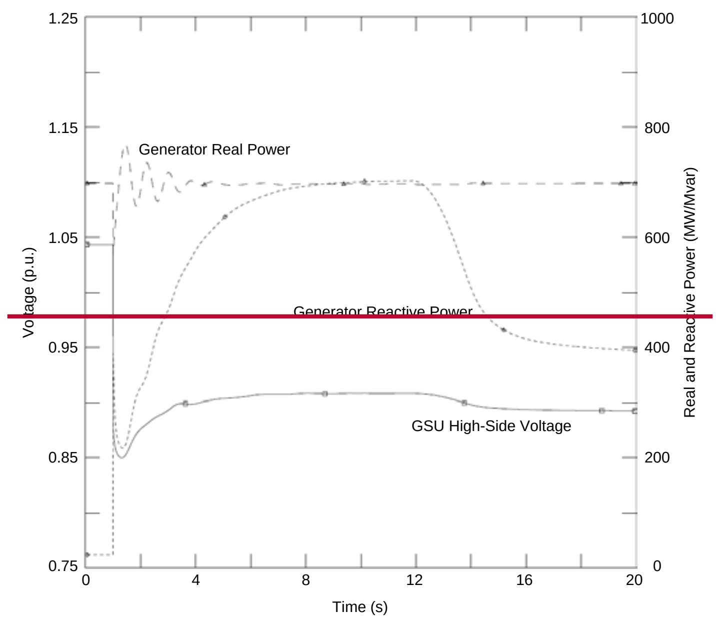
~~In this simulation the following values are derived:~~

$$\cancel{Q = 703.6\ Mvar}$$

$$\cancel{V_{bus} = 0.908 \times V_{nom} = 313.3\ kV}$$

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:~~

$$\cancel{P_{reported} = 700.0\ MW}$$



~~Apparent power (S):~~

~~Eq. (158)~~ $\cancel{S = P_{synch\_reported} + jQ}$

$$\cancel{S = 700.0\,MW + j703.6\,Mvar}$$

$$\cancel{S = 992.5\angle 45.1°\,MVA}$$

~~Primary current (I_{pri}):~~

~~Eq. (159)~~ $$\cancel{I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}}$$

$$\cancel{I_{pri} = \frac{992.5\angle -45.1°\,MVA}{1.73 \times 313.3\,kV}}$$

$$\cancel{I_{pri} = 1831.2\angle -45.1°\,A}$$

~~Secondary current (I_{sec}):~~

~~Eq. (160)~~ $$\cancel{I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}}$$

$$\cancel{I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}}}$$

$$\cancel{I_{sec} = 4.578\angle -45.1°\,A}$$

~~To satisfy the 115% margin in Options 15b and 16b:~~

~~Eq. (161)~~ $$\cancel{I_{sec\,limit} > I_{sec} \times 115\%}$$

$$\cancel{I_{sec\,limit} > 4.578\angle -45.1°\,A \times 1.15}$$

$$\cancel{I_{sec\,limit} > 5.265\angle -45.1°\,A}$$

Example Calculations: Option 17

~~Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.~~

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

~~Eq. (162)~~ $\cancel{P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf}$

Eq. (175) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

~~Eq. (163)~~ $\cancel{Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)}$

Eq. (176) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

~~Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage~~ ~~(V_{bus}):~~

~~Eq. (164)~~ $\cancel{V_{bus} = 1.0\ p.u. \times V_{nom}}$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

~~Eq. (165)~~ $\cancel{S = P + jQ}$

Eq. (178) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option 17

Primary impedance (Z_{pri}):

Eq. (~~166~~179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, and then the maximum allowable impedance reach is:

Eq. (~~169~~182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

Example Calculations: Option 17

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation Elements that connect a~~ relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~ .

Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~170~~183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Options 18 and 19

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high-side~~line nominal voltage (V_{bus}):

Eq. (~~172~~185) $$V_{nom} = 1.0\, p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\, kV$$

$$V_{bus} = 345\, kV$$

Apparent power (S):

Eq. (~~173~~186) $$S = P + jQ$$

$$S = 102.0\, MW + j83.2\, Mvar$$

$$S = 131.6\angle 39.2°\, MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\, MVA}{1.73 \times 345\, kV}$$

$$I_{pri} = 220.5\angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\, A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\, A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 18 and 19

$$I_{sec\,limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{sec\,limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale~~:~~

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

Rationale for R1~~:~~

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Exhibit B

Implementation Plan

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1
Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite Standard

- None

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

This Implementation Plan supersedes and retires the *Implementation Plan PRC-025-1 – Generator Relay Loadability*[1] such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. In drafting this Implementation Plan, the PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the phased-in implementation dates for PRC-025-1. The first U.S. phased-in implementation date for PRC-025-1 of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. phased-in implementation date for PRC-025-1 of October 1, 2021 applies to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities,
- The proposed revisions to Options 14b, 15b, and 16b may give reason for entities to re-evaluate their settings for load-responsive protective relays,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[1] http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_(Clean).pdf

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the later of October 1, 2019 or 12 months after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 – Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the later of October 1, 2021 or 36 months after the effective date of Reliability Standard PRC-025-2, except as noted for the Table 1 Relay Loadability Evaluation Criteria Options listed below

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	**Application and Relay Type**	**Implementation Date**
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V-R – voltage-restrained)[2]	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

[2] Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

None

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Exhibit C

Order No. 672 Criteria

Exhibit C — Order No. 672 Criteria — Proposed Reliability Standard PRC-025-2

<u>Order No. 672 Criteria</u>

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]

The purpose of proposed Reliability Standard PRC-025-2, which is unchanged from currently-effective Reliability Standard PRC-025-1, is to set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

Reliability Standard PRC-025-1 requires applicable entities to apply relay settings in accordance with the criteria table in Attachment 1. Table 1 provides specific setting criteria for load-responsive protective relays in a variety of scenarios, with several options available. Proposed Reliability Standard PRC-025-2 enhances reliability by addressing certain issues that have been identified in the course of implementing PRC-025-1. These revisions include: (i) adding a provision to Attachment 1, Table 1 Relay Loadability Evaluation Criteria to address dispersed power producing resources that are unable to be set at 130 percent of the calculated current due to physical limitations of the protection equipment; (ii) adding to the Table 1 relay type description the protective relay 50 Element associated with instantaneous (i.e. without

[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, 324.

intentional time delay) tripping of overcurrent based protection; (iii) clarifying, in the Table 1 Application column, that an entity must apply settings to all the applications described therein; (iv) clarifying that an entity, when employing simulation for setting relay associated with the transmission line interconnecting the generator or plant to the Transmission system, must simulate the 0.85 per unit depressed voltage at the remote end (i.e. Transmission system side) of the line; (v) removing the term "Pick Up" from the Attachment 1, Table 1 heading (new heading: "Setting Criteria") to better align the setting to the calculated or simulated capability of the generator with an associated margin; and (vi) clarifying certain terminology and references. The revisions provide additional options and clarity, and thus the PRC-025 standard continues to provide a technically sound means of achieving the stated reliability goal.

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. Proposed Reliability Standard PRC-025-2 continues to apply to Generator Owners, Transmission Owners, and Distribution Providers. The proposed Reliability Standard clearly lists the types of Facilities subject to compliance. Table 1 in the proposed Reliability Standard is clear and provides information by application, relay type, voltage, and setting. The proposed standard clearly articulates the actions that each entity must take to comply.

[3] Order No. 672 at P 322, 325.

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 Factor ("VRF") and Violation Severity Level ("VSL") for proposed Reliability Standard PRC-025-2, as reflected in **Exhibit A,** are unchanged from currently-effective Reliability Standard PRC-025-1. The VRF and VSL comport with NERC and Commission guidelines related to their assignment. The VSL is consistent with the corresponding Requirement and does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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

The proposed Reliability Standard includes a Measure that support the proposed standard's sole Requirement by clearly identifying what is required and how the Requirement will be enforced. This Measure, which remains substantively unchanged from the Measure in currently-effective Reliability Standard PRC-025-1, helps provide clarity regarding how the Requirement will be enforced, and helps ensure that the Requirement will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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. The revisions reflected in proposed Reliability Standard PRC-

[4] Order No. 672 at P 326.

[5] Order No. 672 at P 327.

[6] Order No. 672 at P 328.

025-2 effectively address the issues identified during the implementation of PRC-025-1 by clarifying the various options and approaches for setting relays. Further, the proposed standard adds a new setting option, Option 5b, for the overcurrent relay of a Protection System applied to an asynchronous generating unit including an Element utilized in the aggregation of dispersed power producing resources. This new Option helps to ensure reliability in those situations where manufacturer or physical limitations would prevent an entity from being able to set the relay in accordance with the requirements of currently effective PRC-025-1.

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 revisions reflected in proposed Reliability Standard PRC-025-2 provide significant benefits for the reliability of the Bulk Power System by refining relay loadability requirements for generating Facilities to prevent unnecessary tripping of generators during a system disturbance: The proposed Reliability Standard does not sacrifice excellence in operating system reliability for costs associated with implementation of the Reliability Standard.

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 throughout North America and does not favor one geographic area or regional model.

---

[7] Order No. 672 at PP 329, 330.

[8] Order No. 672 at P 331.

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

The proposed Reliability Standard has no undue negative effect on competition. The proposed Reliability Standard requires the same performance by each of applicable entity. The proposed Reliability Standard does not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

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

The proposed effective dates for the proposed Reliability Standard are just and reasonable and appropriately balance the urgency in the need to implement the proposed Reliability Standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for PRC-025-2 that is the first day of the first calendar quarter after regulatory approval. Reliability Standard PRC-025-1 would be retired immediately prior to the effective date of PRC-025-2.

Under the PRC-025-1 Implementation Plan, entities have either 60 or 84 months to come into compliance with the standard, depending on whether the entity can apply settings to its existing relays (October 1, 2019) or whether removal or replacement is necessary (October 1, 2021). The proposed PRC-025-2 implementation plan recognizes that entities are in the process of implementing the standard to meet these dates, but that certain revisions in PRC-025-2 may give reason for entities to re-evaluate their settings for load responsive protective relays or require further time for implementation. The proposed PRC-025-2 implementation plan provides a new phased compliance schedule that is intended to supersede the phased compliance schedule

---

[9] Order No. 672 at P 332.

[10] Order No. 672 at P 333.

provided in the PRC-025-1 Implementation Plan. For existing Options, entities would have at least as much time to come into compliance with the standard as they would have under the PRC-025-1 implementation plan. New phased compliance dates are provided for new and revised Table 1 Relay Loadability Evaluation Criteria Options, including:

- New Option 5b: 24 or 48 months, depending on whether replacement or removal is necessary;
- For the 50 element only in Options 2a, 2b, 2c, 5a, 5b, 8a, 8b, 8c, 11, 13a, and 13b: 60 or 84 months, depending on whether replacement or removal is necessary;
- Revised Options 14b, 15b, 16b: 24 or 48 months, depending on whether replacement or removal is necessary.

For load-responsive relays that later become applicable to the standard, entities would continue to have 60 or 84 months to come into compliance, depending on whether replacement or removal is necessary.

The proposed implementation plan provides additional timing for new Option 5b due to the number of dispersed power generating resources that may be have been unable to apply the existing 130% threshold; however, the burden to adjust the settings to ensure the capability of the resource does not infringe on the protection setting is expected to be minimal.

The proposed implementation plan also provides a full 60 and 84 month implementation timeline to address the newly-added 50 element in certain Options. This timeline accounts for engineering review, potential equipment procurement, and outage coordination to commission the equipment and apply the appropriate settings.

The proposed implementation plan also allows entities sufficient time to address newly-revised Options addressing Transmission lines interconnecting the generating unit or plant to the

Transmission system. The proposed timeframe allows entities to re-evaluate their settings to account for line impedance effects and to make appropriate modifications to the settings.

The proposed effective dates are reflected 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 E** 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, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

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 the proposed Reliability Standard. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

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

No other factors relevant to whether the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential were identified.

---

[11] Order No. 672 at P 334.

[12] Order No. 672 at P 335.

[13] Order No. 672 at P 323.

Exhibit D

Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-04 Modifications to PRC-025-1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. 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 Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for 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 Guidelines for Violation Risk Factors

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

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

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

The FERC 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 for PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF Justifications for PRC-025-1, R1	
Proposed VRF	**High**
Guideline 4- Consistency with NERC Definitions of VRFs	The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

VSLs for PRC-025-2, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications for PRC-025-2, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.

VSL Justifications for PRC-025-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.

VSL Justifications for PRC-025-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Exhibit E

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standard PRC-025-2 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 selected to lead each project in accordance with Section 4.3 of the NERC Standards Process Manual.[2] 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 ("SDT") members is included in **Exhibit F**.

II. Standard Development History

A. Standard Authorization Request Development

Project 2016-04 – Modifications to PRC-025-1 was initiated on August 25, 2016 as a Standards Authorization Request ("SAR") for proposed revisions to existing Reliability Standard PRC-025-1. The SAR was initially posted for a 30-day formal comment period from September 16, 2016 through October 18, 2016. Following two solicitations for nominations, the Standards Committee ("SC") appointed a SAR Drafting Team at its January 2017 meeting. Based on comments received from industry on the first draft of the SAR, a second draft of the SAR was posted for an additional 15-day informal comment period from March 20, 2017 through April 3, 2017. The revised SAR was approved by the SC on April 19, 2017.

---

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2012).

2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

B. First Posting – Comment Period, Initial Ballot and Non-binding Poll

Proposed Reliability Standard PRC-025-2, the associated Implementation Plan, and Violation Risk Factors ("VRFs"), and Violation Severity Levels ("VSLs") were posted for a 45-day formal public comment period from July 25, 2017 through September 8, 2017, with a parallel initial ballot and non-binding poll of the VRFs and VSLs held during the last 10 days of the comment period from August 29, 2017 through September 8, 2017.[3] The initial ballot received 80.45% quorum, and 80.99% approval. The non-binding poll received 78.79% quorum and 85.00% of supportive opinions. There were 43 sets of responses, including comments from approximately 127 different individuals and approximately 96 companies representing all 10 industry segments.[4]

C. Second Draft – Comment Period, Additional Ballot, and Non-binding Poll

Proposed Reliability Standard PRC-025-2 was posted for a 45-day formal comment period from October 30, 2017 through December 13, 2017, with parallel additional ballot and non-binding poll held during the last 10 days of the comment period from December 4, 2017 through December 13, 2017. The additional ballot reached quorum at 81.73% of the ballot pool, and received 88.25% approval. The related non-binding poll reached quorum 78.79% of the ballot pool, and 87.78% of supportive opinions. There were 39 sets of responses, including comments from approximately 126 different individuals and approximately 93 companies, representing all 10 industry segments.[5]

---

[3] The ballot and non-binding poll, and comment period were extended an additional day to reach quorum.

[4] NERC, *Consideration of Comments*, Project 2016-04 - Modifications to PRC-025-2, (October 2017), *available at* http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_Consideration_of_Comments_10302017.pdf.

[5] NERC, *Consideration of Comments*, Project 2016-04 - Modifications to PRC-025-2, (January 2018), *available at* http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_PRC_025_2_Consideration_of_Comments_01092018.pdf.

D. Final Ballot

Proposed Reliability Standard PRC-025-2 was posted for a 10-day final ballot period from January 9, 2018 through January 18, 2018. The proposed Reliability Standard received a quorum of 82.69% and an approval rating of 89.46%.

E. Board of Trustees Approval

Proposed Reliability Standard PRC-025-2 was adopted by the NERC Board of Trustees on February 8, 2018.[6]

F. **Guidelines & Technical Basis Correction**

On February 28, 2018, NERC posted a revised document reflecting a non-substantive correction to an example calculation in the non-enforceable Guidelines and Technical Basis following the proposed standard.

[6] NERC, *Board of Trustees Agenda Package*, Agenda Item 6a (PRC-025-2 – Generator Relay Loadability), *available at* http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_of_Trustees_Open_Agenda_Package_February_8_2018.pdf.

Complete Record of Development

Project 2016-04 Modifications to PRC-025-1

Related Files

Status
The final ballot for **PRC-025-2 – Generator Relay Loadability** concluded **8 p.m. Eastern, Thursday, January 18, 2018**. The voting results can be accessed via the link below. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background
Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, issues have been identified for specific Facility applications and load-responsive protective relays.

Standard(s) Affected – PRC-025-1 – Generator Relay Loadability

Purpose / Industry Need
Potential revisions to the standard are expected to improve flexibility in applying various options and provide clarification to other issues raised in the SAR.

Draft	Actions	Dates	Results	Consideration of Comments
PRC-025-2 Clean **(52)** | Redline to Last Posted **(53)** | Redline to Last Approved **(54)**	Posted for Informational Purposes Only Administrative correction made to the Guidelines and Technical Bases. The reference to "UAT low-side voltage:" has been corrected to "UAT high-side voltage."	02/28/18		

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft PRC-025-2 Clean **(43)** | Redline to Last Posted **(44)** | Redline to Last Approved **(45)** Implementation Plan Clean **(46)** | Redline to Last Posted **(47)** VRF/VSL Justification Clean **(48)** | Redline to Last Posted **(49)**	Final Ballot Info **(50)** Vote	01/09/18 - 01/18/18	Ballot Results **(51)**	
Draft 2 PRC-025-2 Clean **(28)** | Redline to Last Posted **(29)** | Redline to Last Approved **(30)** Implementation Plan Clean **(31)** | Redline to Last Posted **(32)** **Supporting Materials** Unofficial Comment Form (Word) **(33)** VRF/VSL Justification Clean **(34)**| Redline to Last Posted **(35)**	Additional Ballot and Non-binding Poll Updated Info **(36)** Info **(37)** Vote	12/04/17 - 12/13/17	Ballot Results **(39)** Non-binding Poll Results **(40)**	
	Comment Period Info **(38)** Submit Comments	10/30/17 - 12/13/17	Comments Received **(41)**	Consideration of Comments **(42)**

Draft	Actions	Dates	Results	Consideration of Comments
Draft Reliability Standard Audit Worksheet (RSAW) Clean | Redline to Last Posted	Info Send RSAW feedback to: RSAWfeedback@nerc.net	12/07/17 - 12/13/17		
Draft 1 PRC-025-2 Clean **(16)** | Redline to Last Approved **(17)** Implementation Plan **(18)** **Supporting Materials** Unofficial Comment Form (Word) **(19)** VRF/VSL Justification **(20)**	Initial Ballot and Non-binding Poll Updated Info **(21)** Info **(22)** Vote	08/29/17 - 09/08/17 The ballot, non-binding poll, and comment period were extended an additional day to reach quorum	Ballot Results **(24)** Non-binding Poll Results **(25)**	
	Comment Period Info **(23)** Submit Comments	07/25/17 - 09/08/17	Comments Received **(26)**	Consideration of Comments **(27)**
	Join Ballot Pools	07/25/17 - 08/23/17		
	Info	08/02/17 - 09/07/17		

Draft	Actions	Dates	Results	Consideration of Comments
Draft Reliability Standard Audit Worksheet (RSAW) Clean | Redline to Version 1	Send RSAW feedback to: RSAWfeedback@nerc.net			
The Standards Committee Accepted the Standards Authorization Request on April 19, 2017				
Standards Authorization Request (SAR) Clean **(10)** | Redline to Last Posted **(11)** **Supporting Materials** Unofficial Comment Form (Word) **(12)**	Comment Period Info **(13)** Submit Comments	03/20/17 - 04/03/17	Comments Received **(14)**	Consideration of Comments **(15)**
Supplemental SAR Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(8)**	Nomination Period Info **(9)** Submit Nominations	12/06/16 - 12/19/16		
Standards Authorization Request (SAR) **(3)** **Supporting Materials**	Comment Period Info **(5)**	09/16/16 - 10/18/16	Comments Received **(6)**	Consideration of Comments **(7)**

Unofficial Nomination Form

Project 2016-04 Modifications to PRC-025-1
Standards Authorization Request (SAR) Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, September 28, 2016.** This unofficial version is provided to assist SAR drafting team nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at 404-446-9689.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the project background, expected time commitment, and other pertinent information is included below.

Background

The purpose of this project is to revise the standard to improve flexibility in applying various options and provide clarification to other issues raised in the SAR. Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, issues have been identified for specific Facility applications and load-responsive protective relays.

Standards affected: PRC-025-1

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the timeline the SAR drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the entire team for discussion and review. Lastly, an important component of the SAR drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Organization:		E-mail:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2016-04 Modifications to PRC-025-1

Standards Authorization Request (SAR) Drafting Team Nomination Period Open through September 28, 2016

Now Available

Nominations are being sought for SAR drafting team members through **8 p.m. Eastern, Wednesday, September 28, 2016**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the SDT meetings. If appointed by the Standards Committee (SC), you are expected to attend most of the face-to-face meetings as well as participate in meetings held via conference calls.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the SAR drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the entire team for discussion and review. Lastly, an important component of the SAR drafting effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Next Steps

The SC is expected to appoint members to the team in October 2016. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at 404-446-9689.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PRC-025-1 – Generator Relay Loadability		
Date Submitted:	August 25, 2016		
SAR Requester Information for #1			
Name:	Rich Quest		
Organization:	Midwest Reliability Organization		
Telephone:	(651) 855-1704	Email:	rp.quest@midwestreliability.org
SAR Requester Information for #2			
Name:	Jerry Thompson, E.I.T.		
Organization:	Kestrel Power Engineering		
Telephone:	(571) 293-1119	Email:	jerry@kestrelpower.com
SAR Requester Information for #3			
Name:	Joe DePoorter		
Organization:	Madison Gas & Electric		
Telephone:	(608) 252-1599	Email:	JDePoorter@mge.com

Request to propose a new or a revision to a Reliability Standard			
SAR Requester Information for #4			
Name:	Éric Loiselle, ing.		
Organization:	Hydro-Québec TransÉnergie		
Telephone:	(514) 879-4100	Email:	Loiselle.Eric2@hydro.qc.ca
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☒ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR proposes revising PRC-025-1 for four specific problems. 1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed generation resources (DGR). 2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard. 3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s). 4. Prevent a lowering of dependability of protective relays directional toward the transmission system at generating facilities that are remote to the transmission network.
Purpose or Goal (How does this request propose to address the problem described above?):
Consider revising the PRC-025-1 standard through the standards development process to: (1) provide alternative loadability Options for Table 1 specific to DGR; (2) address the inclusion or exclusion of the 50 element (i.e., instantaneous), (3) review Table 1 for proper application where there is more than one application for the available Option(s), and (4) provide alternative or additional Options for Table 1 specific to relay applications that are directional toward the transmission system where the interconnecting transmission line impedance may be a factor in determining the maximum reactive output of the generators and associated relay settings.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):

This SAR proposes the need for revising PRC-025-1 for four specific problems.

1. PRC-025-1, Table 1 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of DGR to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor. This may result in instances of non-compliance due manufacturer requirements or physical limitations of DGR and may result in an overly conservative relay setting. Consider revising the standard to provide alternative options for setting the overcurrent element of a Protection System applied to an asynchronous generating unit and an Element utilized in the aggregation of DGR.
2. There is potential for Generator Owners to apply a pick up setting of the 50 element (i.e., instantaneous overcurrent) of a Protection System, which is not applicable to the standard, that is lower than the minimum pick up established by the standard for the 51 element (i.e., time delayed overcurrent). The 50 element is generally not used in the generator applications where the 51 element is found in the standard. Consider revising the standard to address the inclusion or exclusion of the 50 element for the various overcurrent applications within Table 1.
3. There is potential for Generator Owners not to apply loadability margins to all load-responsive protective relays in Table 1 of PRC-025-1 under the "Application" column that may affect loadability. For example, the Application column from Table 1 (Options 4, 5, and 6):

   > *"Asynchronous generating unit(s) (including inverter-based installations), **or** Elements utilized in the aggregation of dispersed power producing resources."*

   The above clause is separated by an "or" conjunction and may lead the Generator Owner to set one particular application and not the other. This may create a gap in achieving the goal of the standard when loadability margins are not applied to relays on certain Elements. Consider revising the standard to make it clear whether either or both of the listed Elements in the Application column of Options 1-6 must meet the criteria of the particular Option.
4. In the case of remote generating facilities that are electrically weak at its connection to the transmission network, the maximum reactive power required by the specific Table 1 Options is too high to be observed in any recoverable stressed condition. This is due to the system impedance (mainly line impedance) restricting the maximum reactive power output by the generator, no matter the generator characteristics. Lastly, applying the existing Table 1 Options for relay applications directional toward the transmission system results in an overly

SAR Information
conservative relay setting and could require reducing the backup protection coverage in order to comply with the stressed system condition anticipated by the standard.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The PRC-025-1 standard became effective on October 1, 2014 and has a phased implementation of five and seven years (i.e., 2019 or 2021) depending on the scope of work required by the Generator Owner. During the early stages of implementation, the above four problems were revealed by industry. The scope of work will be to consider providing (1) an alternative loadability margin for DGR, (2) revision that includes or excludes 50 element for overcurrent applications, (3) clarification of the application of the Elements in Table 1 of PRC-025-1 for each option that has two applicable Elements separated by an "or" conjunction, and (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the transmission.
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.)
1. Consider revising the PRC-025-1 standard concerning #1 above through the standards development process to provide a means to determine alternative loadability Options for Table 1 of the standard specific to DRG equipment where there could be a manufacturer requirement or physical equipment limitation. Similar to the provisions already contained in the standard, consider methods that would eliminate the potential for non-compliance and/or a violation of manufacturer specifications. For example: (a) a provision could allow a margin consistent with the manufacturer's requirements or based on the limitation of the equipment; (b) a provision to allow the DRG output to be studied through simulation (e.g., similar to Options 1c and 2c) and the relays to be set with an appropriate margin determined through the standard development process; (c) a provision to exempt equipment with fixed limitations installed prior to the effective date of PRC-025-1 or other justifiable date; and/or (d) any other equally effective and efficient method to accomplish the goal. 2. Consider revising the PRC-025-1 standard concerning #2 above to address the inclusion or exclusion of the 50 element (i.e., instantaneous overcurrent) of a Protection System with or without intentional time delay. Newer techniques in generator protection applications may result in a gap due to non-traditional applications of generator overcurrent relays.

SAR Information
3. Consider revising the PRC-025-1 standard concerning #3 above through the standards development process to bring awareness and clarification whether either or both of the Elements listed in the “Application” column of Table 1, Options 1-6 are to have loadability margins applied to the load-responsive protective relays. 4. Consider revising the PRC-025-1 standard concerning #4 above through the standards development process to provide a means to determine alternative loadability Option(s) for Table 1 of the standard specific to relays directional toward the transmission system. Similar to the provisions already contained in the standard, consider: (a) alternative Options for relay settings where the interconnecting transmission line impedance has a significant impact the maximum reactive output of the generating facility and the associated relay settings, (b) the technical validity of the existing options in the presence of significant transmission line impedance between generation and the network, and/or (c) any other equally effective and efficient method to address the problem of significant line impedance effecting how phase protective relays are set not limit generator loadability while maintaining reliable protection of the BES for all fault conditions.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ 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.

Reliability Functions		
☐	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.
☐	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.

Reliability and Market Interface Principles	
☐	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 with that standard.	Yes
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
None.	

Related SARs	
SAR ID	Explanation
None.	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2016-04 Modifications to PRC-025-1 Standards Authorization Request (SAR)

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2016-04 Modifications to PRC-025-1 (Generator Relay Loadability) SAR**. The electronic form must be submitted by **8 p.m. Eastern, Tuesday, October 18, 2016.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at 404-446-9689.

Background

Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, four specific issues have been identified.

Summary

The SAR proposes that the PRC-025-1 standard be revised to provide: (1) an alternative loadability margin for dispersed generation resources; (2) an inclusion or exclusion of the 50 overcurrent element, (3) clarification on whether the Elements in the “Application” column of Table 1 of PRC-025-1 that have two applications separated by an “or” conjunction should both be included or may one or the other be selected; and (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the transmission.

Questions

1. Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.

   ☐ Yes
   ☐ No

   Comments:

2. Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.

   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

Standards Announcement

Project 2016-04 Modifications to PRC-025-1
Standards Authorization Request (SAR)

Formal Comment Period Open through October 18, 2016

Now Available

A 30-day formal comment period for the **Project 2016-04 Modifications to PRC-025-1** SAR, is open through **8 p.m. Eastern, Tuesday, October 18, 2016**.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the Standards Balloting & Commenting System due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

Next Steps

The drafting team will consider all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at 404-446-9689.

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

Comment Report

Project Name:	2016-04 Modifications to PRC-025-1 SAR
Comment Period Start Date:	9/16/2016
Comment Period End Date:	10/18/2016
Associated Ballots:	

There were 14 sets of responses, including comments from approximately 14 different people from approximately 13 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.

2. Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	IRC Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Mark Holman	PJM	2	RF
					Matt Goldberg	ISONE	2	NPCC
					Lori Spence	MISO	2	MRO
					Christina Bigelow	ERCOT	2	Texas RE
					Ali Miremadi	CAISO	2	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC

					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Stephanie Johnson	Westar Energy	1,3,5,6	SPP RE

1. Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name IRC Standards Review Committee

Answer	No
Document Name	
Comment	

The SRC agrees there is a technical need for protection systems to accommodate configurations for Distributed Generation. However, the proposed solution to modify certain parts of Table 1 may be challenging to audit and to enforce due to the variations in loadability that needs to be considered for different feeder configurations. We recommend that other alternatives instead of a change to PRC-0025 be pursued first.   A Guideline may be just as effective to address the problem. Furthermore, additional requiremements in Table 1 intended to specify how 50 element relays should be set to accommodate DGR on feeders may only lead to subsequent interpretation requests or further SARs when there is a configuration not foreseen by the SDT.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	
Comment	

Need to limit the scope of the SAR such that change will only apply to DGR type resources. In our interpretation, we feel that the expansion of the scope may open up the opportunity to include other types of resources which could change the original intents for the DGR Resource.

Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5

Answer	Yes
Document Name	
Comment	

The four considerations proposed in the Request are reasonable. It addressees flexibility provision requests for distributed generation resources and addresses potential gaps initiated by new technologies

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer	Yes
Document Name	

Comment

Austin Energy (AE) agrees generally with the scope and objectives. With respect to Item #2, AE makes the following suggestion:

When addressing the 50 element (i.e., instantaneous overcurrent) PRC-025 should provide clarity regarding how to set the time dial settings. Specifically, either: (1) include a requirement regarding how to set the time dial settings (e.g. instantaneous or delayed) or (2) if time dial settings are irrelevant, ensure PRC-025 makes it clear Registered Entities may set the time dials however they wish.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

We agree that a SAR is necessary to address the issues identified with PRC-025-1. However, we believe portions of the proposed scope and objectives are too restrictive. We list these concerns in response to your next question.

Likes 0	
Dislikes 0	

Response

Karen Yoder - FirstEnergy - FirstEnergy Corporation - NA - Not Applicable - RF

Answer	Yes
Document Name	

Comment	
FirstEnergy has reviewed the SAR and agrees with the scope of the project.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
It's inappropriate to solict additional items to add to the SAR Scope. There is no clarity on what the drafting is looking for as well as the issues of compliance if additional items are added to the SAR.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	
No,	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - NA - Not Applicable - RF	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	

PRC-025-1, Table 1 specifies certain relay settings shall be set relative to 115% of the Real Power output capability “reported to the Transmission Planner”. This value is reported in a variety of ways and using a variety of methodologies, which can differ between entities and the needs or desires of a given TP’s MOD-032 documentation. Transmission Planners use generator capability values for different purposes than relay engineers, which could result in a conflict between the goal of PRC-025-1 and the data it requires to be used. The Transmission Planner should use values that can represent a generator’s expected maximum output over an entire (future) season, whereas the relays should be set considering the absolute maximum physical capabilities of the equipment, which may be values that occur for only a few hours and are highly dependent on ambient conditions that the TP may not assume are present for a “seasonal” case. Although the standard allows the user to set relays more conservatively (e.g. use a greater margin than 115% minimum), the implication of this recommendation being included in Table 1 is that it is a safe minimum, when in fact, by instructing GOs to use the values supplied to the TP, the standard could be giving them an unsafe value.

One easy example is that many combustion turbine generators, when operated in temperature control, can have a much wider variation between peak output and maximum output during peak system conditions than the 115% margin the standard is calling for (for example, the TP needs a maximum capability that it can rely upon being available at 4pm on a hot summer day, while the same CT output could be 20% greater on a cool evening). The standard should be revised such that 115% of the value supplied to the TP is the bar for compliance (because that ensures transmission planning model conditions are upheld) but that it is clearly stated that the protection engineer may desire to use the actual maximum peak capability of the machine considering all expected ambient conditions through the year.

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	

Answer	Yes
Document Name	

Comment

(1) We believe objective #1 should be expanded to include “dispersed power producing resources,” which better aligns with the BES Definition and the standard’s applicable facilities.

(2) Objective #4 fails to incorporate the use of several NERC Glossary of Terms like Transmission, Element, and Reactive Power. We believe the introduction of these defined terms would better clarify the intent of this objective. We propose rewording Scope #4 to “provide alternative or additional Table 1 Options specific to relay applications that are directional towards the Transmission system where Elements’ impedances may factor in determining the Reactive Output of dispersed power producing resources and associated relay settings.”

(3) We recommend references to “50 element” should cite IEEE Standard C37.2-2008.

(4) We believe the example provided under Objective 3 is limited. The concern presented is the use of “or” in the application column for options 4, 5, and 6 of Table 1. We believe that the Table should clarify which options an entity should use for “Elements utilized in the aggregation of dispersed power producing resources,” as currently any options between 1-6, depending on the relay type, can be used.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Duke Energy recommends that the drafting team consider adding in the SAR, or amending the PRC-025-1 standard to include and Option 13 C (see below) utilizing Low side protective device (overcurrent) on a Unit Auxiliary Transformer. Currently, the standards includes high side device options, but does not include one for the low side device. Duke believes that this exclusion is improper, and recommends that a Low side protective device alternative be included in the standard as describe below. For further technical rationale as to this inclusion, we recommend the review of a document drafted by the NERC System Protection and Control Subcommittee titled *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition- NERC System Protection and Control Subcommittee March 2016*.

Option 13c-Coordinate UAT high-side protection based on a UAT low-side overcurrent setting recommendation.

Set load-responsive relay applied on the low side of the UAT set with a minimum pickup value of 135% of the transformer nameplate.(In some situations it may be desirable to set this low-side relay lower than 135% of the transformer nameplate. This could be to protect equipment or because the load on the transformer may be much less than the nameplate rating of the transformer. If this approach is used, then it is recommended that the settings must be 135% of the maximum load on the UAT.)

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
It appears the SAR is taking an approach to Table 1 to make it an all inclusive list for every possible generator interface requiring a different loadability setting. If the SAR team believes this is necessary for PRC-025 so entities can abide by relay manufacturer specifications and also meet NERC standards compliance, it should reconsider how much detail is appropriate for Table 1. There is always a need to allow entities an appropriate level of engineering judgment for seting relays because of the numerous configurations of assets on the system. Can Table 1 feasibly be revised to capture all needs?	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Additional clarification is requested in PRC-025-1 - Attachment 1: Relay Settings under Multiple Lines. Specifically, the final sentence states that "[t]hese topologies [e.g., multiple lines that connect the GSU transformer(s) to the Transmission system] can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard." If multiple lines are substantially parallel in nature, is it permissable for entities to apply the most appropriate Option 14a, 15a, 16a, 17, 18, or 19 and divide the current by the number of substantially parallel lines?	
Likes 0	
Dislikes 0	
Response	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
1. Are relay assessments required both at the turbine level and the aggregate generation level or both? The current Standard does not make this clear as other recently developed PRC Standards (e.g. PRC-024) do.	

2. All wind turbines on a feeder don't always act the same. Does that mean a wind farm has to evaluate the Protection Systems at each individual turbine? This question was raised during the original PRC-025 Standard Development in 2010 but the SDT was not consistent in addressing this line of questioning during the Consideration of Comments. Our opinion is that this level of assessment is not necessary and that only the Protection Systems at the point of aggregation (> 75 MVA) need to be evaluated. We question the value of checking each individual relay especially in light of the recent Project: Cost Effective Pilot.

3. The Standard does not make it clear if wind turbines of various Types (I through IV) should be considered asynchronous or synchronous generation and therefore which Option to choose for the relay assessment is unclear.

4. There should be Requirement language in PRC-025 that speaks to coordination with TOP and how changes may affect other relay settings at the Facility before changes are made to relay settings. There should also be an exemption due to technical limitations of equipment such as in the Requirement language of PRC-024.

5. There should be an evaluation by a SDT (this team or another separate one) on how all recent PRC-developed Standards that are requiring relay setting changes are interacting or possibly causing conflicts with each other.

6. A simplified guidebook or process diagram is needed to explain the steps of the process to perform the relay assessment.

Likes 0	
Dislikes 0	

Response

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

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	
Document Name	
Comment	
No.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) We thank the individuals listed and others who supported the issuance of this SAR. We agree the concerns listed regarding PRC-025-1 are pressing. Moreover, we believe revising the implementation plan should be included, as the 60-month or 84-month 100% compliance window identified within the current implementation plan has already proceeded. We believe the window should be reset or a phased-in compliance approach used instead. (2) We believe the SDT should be allowed to consider Paragraph 81 criteria where possible in this standard. We also recommend the SDT be given direction to consolidate where appropriate within this standard. The Technical and Applications Guidelines section of this document is over 70 pages long and would be better served in a Reliability Guideline or supporting white paper. (3) We believe Reliability Principles #4, pertaining to Facilities provided for monitoring and control, should be checked for this SAR, as it pertains to protection relays. (4) We believe the SDT should seek input from appropriate NERC technical task forces, such as the Distributed Energy Resources Task Force. The purpose of this task force is to examine potential reliability implications caused by operational and planning Distributed Energy Resource impacts. (5) We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - NA - Not Applicable - RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Additional comments received from Ruida Shu – NPCC

1. Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.

   ☒ Yes

   ☐ No

   Comments:

2. Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.

   ☒ Yes

   ☐ No

   Comments:

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

   Comments:

   RSC supports the SAR for Project 2016-04 Modifications to PRC-025-1 (Generator Relay Loadability).

Consideration of Comments

Project Name: 2016-04 Modifications to PRC-025-1

Comment Period Start Date: 9/16/2016

Comment Period End Date: 10/18/2016

There were 14 sets of responses, including comments from approximately 35 different people from approximately 29 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Summary

Draft 1 of the SAR proposed that the PRC-025-1 standard be revised to provide: (1) an alternative loadability margin for dispersed generation resources; (2) an inclusion or exclusion of the 50 overcurrent element, (3) clarification on whether the Elements in the "Application" column of Table 1 of PRC-025-1 that have two applications separated by an "or" conjunction should both be included or may one or the other be selected; and (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the transmission. This scoping has not change substantively.

In addition to the above four items, Draft 2 of the SAR proposes the following items in summary form: (5) Modify or eliminate the use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection

methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to “not trip” based on the criteria in Table 1; and (6) Miscellaneous clarifications, which include:

a. Consider the use of references to the American National Standards Institute (ANSI) device numbers given that some equipment may not use traditional nomenclature.
b. Consider whether it is clear and appropriate when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based and dispersed power producing resources.
c. Clarify that a high unit capability may be used other than the value “reported to the Transmission Planner,” which is a minimum capability.
d. Clarify that CB103 relay is applicable to the standard.

Questions

1. **Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.**
2. **Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.**
3. **If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.**

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Scott Brame	North Carolina	3,4,5	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Electric Membership Corporation		
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	IRC Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Mark Holman	PJM	2	RF
					Matt Goldberg	ISONE	2	NPCC
					Lori Spence	MISO	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Christina Bigelow	ERCOT	2	Texas RE
					Ali Miremadi	CAISO	2	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Stephanie Johnson	Westar Energy	1,3,5,6	SPP RE

1. Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
The SRC agrees there is a technical need for protection systems to accommodate configurations for Distributed Generation. However, the proposed solution to modify certain parts of Table 1 may be challenging to audit and to enforce due to the variations in loadability that needs to be considered for different feeder configurations. We recommend that other alternatives instead of a change to PRC-0025 be pursued first. A Guideline may be just as effective to address the problem. Furthermore, additional requirements in Table 1 intended to specify how 50 element relays should be set to accommodate DGR on feeders may only lead to subsequent interpretation requests or further SARs when there is a configuration not foreseen by the SDT.	
Likes 0	
Dislikes 0	
Response	
The SAR team notes that the aggregation of dispersed generation resources is addressed in Applicability "3.2.5 Elements utilized in the aggregation of dispersed power producing resources." The team has included consideration of feeders. Change made to the SAR.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

Need to limit the scope of the SAR such that change will only apply to DGR type resources. In our interpretation, we feel that the expansion of the scope may open up the opportunity to include other types of resources which could change the original intents for the DGR Resource.	
Likes 0	
Dislikes 0	
Response	
The SAR team notes that the proposed SAR focus is to address conditions where DGR cannot meet the intent of the standard due to equipment limitations. To avoid reopening the standard again later for known issues, it is best to capture the known issues and address them collectively during the revision of the standard. No change was made to the SAR.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	Yes
Document Name	
Comment	
The four considerations proposed in the Request are reasonable. It addressees flexibility provision requests for distributed generation resources and addresses potential gaps initiated by new technologies	
Likes 0	
Dislikes 0	
Response	
The SAR team thanks you for your comment.	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	

Austin Energy (AE) agrees generally with the scope and objectives. With respect to Item #2, AE makes the following suggestion: When addressing the 50 element (i.e., instantaneous overcurrent) PRC-025 should provide clarity regarding how to set the time dial settings. Specifically, either: (1) include a requirement regarding how to set the time dial settings (e.g. instantaneous or delayed) or (2) if time dial settings are irrelevant, ensure PRC-025 makes it clear Registered Entities may set the time dials however they wish.	
Likes 0	
Dislikes 0	
Response	
The SAR team notes that time periods are not a consideration in the standard. No change made to the SAR.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We agree that a SAR is necessary to address the issues identified with PRC-025-1. However, we believe portions of the proposed scope and objectives are too restrictive. We list these concerns in response to your next question.	
Likes 0	
Dislikes 0	
Response	
The SAR team thanks you for your comment.	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - NA - Not Applicable - RF	
Answer	Yes
Document Name	
Comment	

FirstEnergy has reviewed the SAR and agrees with the scope of the project.	
Likes 0	
Dislikes 0	
Response	
The SAR team thanks you for your comment.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
It's inappropriate to solicit additional items to add to the SAR Scope. There is no clarity on what the drafting is looking for as well as the issues of compliance if additional items are added to the SAR.	
Likes 0	
Dislikes 0	
Response	
The SAR team thanks you for your comment. The process allows for capturing issues with the standard so that any unforeseen issues are captured before opening the standard. No change was made to the SAR.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	No
Document Name	
Comment	
No,	
Likes 0	
Dislikes 0	
Response	
Jeri Freimuth - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - NA - Not Applicable - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	

PRC-025-1, Table 1 specifies certain relay settings shall be set relative to 115% of the Real Power output capability "reported to the Transmission Planner". This value is reported in a variety of ways and using a variety of methodologies, which can differ between entities and the needs or desires of a given TP's MOD-032 documentation. Transmission Planners use generator capability values for different purposes than relay engineers, which could result in a conflict between the goal of PRC-025-1 and the data it requires to be used. The Transmission Planner should use values that can represent a generator's expected maximum output over an entire (future) season, whereas the relays should be set considering the absolute maximum physical capabilities of the equipment, which may be values that occur for only a few hours and are highly dependent on ambient conditions that the TP may not assume are present for a "seasonal" case. Although the standard allows the user to set relays more conservatively (e.g. use a greater margin than 115% minimum), the implication of this recommendation being included in Table 1 is that it is a safe minimum, when in fact, by instructing GOs to use the values supplied to the TP, the standard could be giving them an unsafe value.

One easy example is that many combustion turbine generators, when operated in temperature control, can have a much wider variation between peak output and maximum output during peak system conditions than the 115% margin the standard is calling for (for example, the TP needs a maximum capability that it can rely upon being available at 4pm on a hot summer day, while the same CT output could be 20% greater on a cool evening). The standard should be revised such that 115% of the value supplied to the TP is the bar for compliance (because that ensures transmission planning model conditions are upheld) but that it is clearly stated that the protection engineer may desire to use the actual maximum peak capability of the machine considering all expected ambient conditions through the year.

Likes 0	

Dislikes 0	
Response	

The SAR team notes that the generator output is based on MOD-025-2 (*Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability*). The original PRC-025-1 team based this minimum criteria on the reported value to the Transmission Planner to establish a clear value to be used in the relay loadability calculations. The SAR team considers this a clarification to the intent of the Table 1 language, and is recommending consideration in the Guidelines and Technical Basis. No change was made to the SAR.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	
Comment	

(1) We believe objective #1 should be expanded to include "dispersed power producing resources," which better aligns with the BES Definition and the standard's applicable facilities.

(2) Objective #4 fails to incorporate the use of several NERC Glossary of Terms like Transmission, Element, and Reactive Power. We believe the introduction of these defined terms would better clarify the intent of this objective. We propose rewording Scope #4 to "provide alternative or additional Table 1 Options specific to relay applications that are directional towards the Transmission system where Elements' impedances may factor in determining the Reactive Output of dispersed power producing resources and associated relay settings."

(3) We recommend references to "50 element" should cite IEEE Standard C37.2-2008.

(4) We believe the example provided under Objective 3 is limited. The concern presented is the use of "or" in the application column for options 4, 5, and 6 of Table 1. We believe that the Table should clarify which options an entity should use for "Elements utilized in the aggregation of dispersed power producing resources," as currently any options between 1-6, depending on the relay type, can be used.

Likes 0	
Dislikes 0	
Response	

1) The SAR team notes that the PRC-025-1 standard Applicability (i.e., “3.2.5 Elements utilized in the aggregation of dispersed power producing resources.”) uses the same phrase as the Bulk Electric System (BES) definition for Inclusion I4. Change made to the SAR. 2) The SAR team has made the changes to Transmission, Element (where applicable), and Reactive Power. Change made to the SAR. 3) The SAR team has added the reference to IEEE Standard C37.2-2008 to the SAR for consideration for inclusion in the standard where ANSI device numbers are used. Change made to the SAR. 4) The SAR team has modified the SAR to recommend providing a separate set of options for those applications that have more than one application listed in Table 1. Change made to the SAR.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy recommends that the drafting team consider adding in the SAR, or amending the PRC-025-1 standard to include and Option 13 C (see below) utilizing Low side protective device (overcurrent) on a Unit Auxiliary Transformer. Currently, the standards includes high side device options, but does not include one for the low side device. Duke believes that this exclusion is improper, and recommends that a Low side protective device alternative be included in the standard as describe below. For further technical rationale as to this inclusion, we recommend the review of a document drafted by the NERC System Protection and Control Subcommittee titled *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition- NERC System Protection and Control Subcommittee March 2016*. Option 13c-Coordinate UAT high-side protection based on a UAT low-side overcurrent setting recommendation. Set load-responsive relay applied on the low side of the UAT set with a minimum pickup value of 135% of the transformer nameplate.(In some situations it may be desirable to set this low-side relay lower than 135% of the transformer nameplate. This could be to protect equipment or because the load on the transformer may be much less than the nameplate rating of the transformer. If this approach is used, then it is recommended that the settings must be 135% of the maximum load on the UAT.)	
Likes 0	
Dislikes 0	
Response	

The SAR team notes that the original PRC-025-1 standard drafting team addressed the low-side unit auxiliary transformers (UAT) as an unsolved issue in the development of the standard. The NERC System Protection and Control Subcommittee (SPCS) addressed the concern in their guidance document *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition,* and states that "[b]ased upon the information contained within this report, the SPCS recommends no further action." The SAR team thanks you for the suggestion for a new Option 13c and notes that all protection systems must be coordinated. The high-side UAT relays must be set to achieve the loadability requirements of the standard while achieving the necessary coordination with the low-side UAT relays. No change made to the SAR.

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
It appears the SAR is taking an approach to Table 1 to make it an all inclusive list for every possible generator interface requiring a different loadability setting. If the SAR team believes this is necessary for PRC-025 so entities can abide by relay manufacturer specifications and also meet NERC standards compliance, it should reconsider how much detail is appropriate for Table 1. There is always a need to allow entities an appropriate level of engineering judgment for seting relays because of the numerous configurations of assets on the system. Can Table 1 feasibly be revised to capture all needs?	
Likes 0	
Dislikes 0	
Response	
The proposed SAR is scoped in a manner to allow a standard drafting team the flexibility to determine how to address these Facilities, while considering whether the expansion of Table 1 is the best approach. However, the SAR team considered this comment when developing the additional language to the SAR item No. 3.	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	

Comment	
Additional clarification is requested in PRC-025-1 - Attachment 1: Relay Settings under Multiple Lines. Specifically, the final sentence states that "[t]hese topologies [e.g., multiple lines that connect the GSU transformer(s) to the Transmission system] can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard." If multiple lines are substantially parallel in nature, is it permissable for entities to apply the most appropriate Option 14a, 15a, 16a, 17, 18, or 19 and divide the current by the number of substantially parallel lines?	
Likes 0	
Dislikes 0	
Response	
The SAR team notes that although the standard mentions that simulations may be required, simulations are not mandatory, provided that an entity can offer a sound engineering basis for the methodology employed. With respect to the specific alternative mentioned, the SAR team notes that substantially parallel does not equate to substantially equal in impedance. Although an entity would need to provide more information to explain and justify the use of the stated methodology, there may be specific scenarios in which it is and also where it is not appropriate. The SAR team believes the standard language leaves the method of addressing this concern up to the individual registered entity/owner, and recognizes that there may be a number of different potential configurations and considerations in instances of multiple-line connections. The SAR team believes it would not be reasonable to attempt to add all possible scenarios involving multiple-line connections explicitly to the standard, particularly given that multiple-line connections represent a small fraction of the generator tie lines in current service. The SAR drafting team believes the existing standard language allows appropriate flexibility to entities regarding how compliance is achieved and does not require revision. No change made to the SAR.	
Brian Evans-Mongeon - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	

1. Are relay assessments required both at the turbine level and the aggregate generation level or both? The current Standard does not make this clear as other recently developed PRC Standards (e.g. PRC-024) do.

2. All wind turbines on a feeder don't always act the same. Does that mean a wind farm has to evaluate the Protection Systems at each individual turbine? This question was raised during the original PRC-025 Standard Development in 2010 but the SDT was not consistent in addressing this line of questioning during the Consideration of Comments. Our opinion is that this level of assessment is not necessary and that only the Protection Systems at the point of aggregation (> 75 MVA) need to be evaluated. We question the value of checking each individual relay especially in light of the recent Project: Cost Effective Pilot.

3. The Standard does not make it clear if wind turbines of various Types (I through IV) should be considered asynchronous or synchronous generation and therefore which Option to choose for the relay assessment is unclear.

4. There should be Requirement language in PRC-025 that speaks to coordination with TOP and how changes may affect other relay settings at the Facility before changes are made to relay settings. There should also be an exemption due to technical limitations of equipment such as in the Requirement language of PRC-024.

5. There should be an evaluation by a SDT (this team or another separate one) on how all recent PRC-developed Standards that are requiring relay setting changes are interacting or possibly causing conflicts with each other.

6. A simplified guidebook or process diagram is needed to explain the steps of the process to perform the relay assessment.

Likes 0	
Dislikes 0	

Response

1. The SAR team notes that it is both. In Table 1, both the generator and Elements utilized in the aggregation of dispersed power producing resources are listed under the various Options. The SAR is scoped to make this situation clear that both are applicable. No change was made to the SAR.

2. The cost effectiveness is recognized by allowing the Generator Owner to determine settings depending on its fleet (e.g., types and sizes of various resources). The SAR team revised the SAR to consider clarifying that the standard is requiring an assessment from each generating source through the feeders and up through the interconnecting transmission line by adding a bulleted list. Change made to the SAR.

3. The SAR team identified a concern based on the comment in the Guidelines and Technical Basis "Asynchronous Generator Performance" section. This first sentence: "Asynchronous generators, however, do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond" needs to be clarified. Change made to the SAR.

4. The SAR team notes that coordination will be covered in the future PRC-027-1 standard pending regulatory approval. The SAR intends on addressing equipment with limitations with alternative options. No change was made to the SAR.

5. The SAR team notes that the PRC family of the standards are planned for review in 2017 according to the 2017-2019 Reliability Standards Development Plan (RSDP). However, the SAR team believes that the SAR will address this issue by incorporating alternative options for Facilities with limitations. No change was made to the SAR.

6. The SAR team notes that the standard is to address the "what" and not the "how." No change was made to the SAR.

3. *If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.*	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5	
Answer	
Document Name	
Comment	
No.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) We thank the individuals listed and others who supported the issuance of this SAR. We agree the concerns listed regarding PRC-025-1 are pressing. Moreover, we believe revising the implementation plan should be included, as the 60-month or 84-month 100% compliance window identified within the current implementation plan has already proceeded. We believe the window should be reset or a phased-in compliance approach used instead. (2) We believe the SDT should be allowed to consider Paragraph 81 criteria where possible in this standard. We also recommend the SDT be given direction to consolidate where appropriate within this standard. The Technical and Applications Guidelines section of this document is over 70 pages long and would be better served in a Reliability Guideline or supporting white paper.	

(3) We believe Reliability Principles #4, pertaining to Facilities provided for monitoring and control, should be checked for this SAR, as it pertains to protection relays. (4) We believe the SDT should seek input from appropriate NERC technical task forces, such as the Distributed Energy Resources Task Force. The purpose of this task force is to examine potential reliability implications caused by operational and planning Distributed Energy Resource impacts. (5) We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
1. The SAR team notes that the implementation plan will be determined by the standard drafting team that makes the actual modifications to the standard. No change was made to the SAR. 2. The SAR team notes that this standard was developed during the time paragraph 81 items were considered. The SAR team has not found any items that qualify for P81.[1] No change was made to the SAR. 3. The SAR team believes that the reliability principle noted is #5 ("Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems."). The team does not believe protection systems are included in this principle. No change was made to the SAR. 4. The SAR team believes it is good and that it's the drafting team's responsibility to obtain feedback from a variety of sources, such as, the NERC task forces and previous drafting teams (i.e., Distributed Energy Resources Task Force and Dispersed Generation Resources Standards Drafting Team). No change was made to the SAR. 5. Thank you for your comments.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	

[1] On March 15, 2012, the Federal Energy Regulatory Commission ("FERC" or the "Commission") issued an order on the North American Electric Reliability Corporation's ("NERC") Find, Fix and Track ("FFT") process that stated in paragraph 81 ("P81").

Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Karen Yoder - FirstEnergy - FirstEnergy Corporation - NA - Not Applicable - RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

Additional comments received from Ruida Shu – NPCC

1. Do you agree with the scope and objectives of the four items raised in the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you. Please identify additional scoping items in the next question.

   ☒ Yes
   ☐ No
   Comments:

2. Do you have any additional items not scoped in this SAR? If so, please explain the technical rationale for the additional items.

   ☒ Yes
   ☐ No
   Comments:

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

   Comments:

   RSC supports the SAR for Project 2016-04 Modifications to PRC-025-1 (Generator Relay Loadability).

   Response: The SAR team thanks you for your comments.

End of Report

Unofficial Nomination Form

Updated December 7, 2016

Project 2016-04 Modifications to PRC-025-1
Standards Authorization Request (SAR) Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Monday, December 19, 2016.** This unofficial version is provided to assist SAR drafting team nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at 404-446-9689.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the project background, expected time commitment, and other pertinent information is included below.

Background

The purpose of this project is to revise the standard to improve flexibility in applying various options and provide clarification to other issues raised in the SAR. Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, issues have been identified for specific Facility applications and load-responsive protective relays.

Standards affected: PRC-025-1

The time commitment for this project is expected to be two to three conference calls in late January 2017. Generator Owners in all regions with a background in protection systems should consider nominating. The area of focus will be wind/solar protection system requirements and protection systems for plants (synchronous & asynchronous) that are remote to transmission (+20 miles) where the line impedance may have an impact on the settings prescribed by the standard. Individuals appointed to the SAR team will be encouraged to nominate for the subsequent standard drafting team.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested SAR Drafting Team (Bio):

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	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, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Updated December 7, 2016

Project 2016-04 Modifications to PRC-025-1

Supplemental SAR Drafting Team Nomination Period Open through December 19, 2016

Now Available

Nominations are being sought for additional SAR drafting team members through **8 p.m. Eastern, Monday, December 19, 2016**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the SDT meetings. If appointed by the Standards Committee (SC), you are expected to attend most of the face-to-face meetings as well as participate in meetings held via conference calls.

The time commitment for this project is expected to be two to three conference calls in late January 2017. Generator Owners in all regions with a background in protection systems should consider nominating. The area of focus will be wind/solar protection system requirements and protection systems for plants (synchronous & asynchronous) that are remote to transmission (+20 miles) where the line impedance may have an impact on the settings prescribed by the standard. Individuals appointed to the SAR team will be encouraged to nominate for the subsequent standard drafting team.

Next Steps

The SC is expected to appoint members to the team early 2017. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at (404) 446-9689.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PRC-025-1 – Generator Relay Loadability		
Date Submitted:	August 25, 2016		
SAR Requester Information for #1			
Name:	Rich Quest		
Organization:	Midwest Reliability Organization		
Telephone:	(651) 855-1704	Email:	rp.quest@midwestreliability.org
SAR Requester Information for #2			
Name:	Jerry Thompson, E.I.T.		
Organization:	Kestrel Power Engineering		
Telephone:	(571) 293-1119	Email:	jerry@kestrelpower.com
SAR Requester Information for #3			
Name:	Joe DePoorter		
Organization:	Madison Gas & Electric		
Telephone:	(608) 252-1599	Email:	JDePoorter@mge.com

Request to propose a new or a revision to a Reliability Standard			
SAR Requester Information for #4			
Name:	Éric Loiselle, ing.		
Organization:	Hydro-Québec TransÉnergie		
Telephone:	(514) 879-4100	Email:	Loiselle.Eric2@hydro.qc.ca
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☒ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR proposes revising PRC-025-1 the following specific problems. 1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed power producing resources. 2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard. 3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s). 4. Prevent a lowering of dependability of protective relays directional toward the Transmission system at generating facilities that are remote to the transmission network. 5. Modify or eliminate the use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to “not trip” based on the criteria in Table 1. 6. Miscellaneous considerations for clarifications to the standard, Attachment 1, and/or Application Guidelines.
Purpose or Goal (How does this request propose to address the problem described above?):
Consider revising the PRC-025-1 standard through the standards development process to: (1) provide alternative loadability Options for Table 1 specific to dispersed power producing resources; (2) address

SAR Information
the inclusion or exclusion of the 50 element[1] (i.e., instantaneous), (3) review Table 1 for proper application where there is more than one application for the available Option(s), (4) provide alternative or additional Options for Table 1 specific to relay applications that are directional toward the Transmission system where the interconnecting transmission line impedance may be a factor in determining the maximum Reactive Power output of the generators and associated relay settings, (5) provide an alternative to the term "pickup setting" in Table 1 the will better align with the intent of the standard for relays to "not trip", and (6) provide clarity on identified miscellaneous items.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
This SAR proposes the need for revising PRC-025-1 for the following specific problems. 1. PRC-025-1, Table 1 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of dispersed power producing resources to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor. This may result in instances of non-compliance due manufacturer requirements or physical limitations of dispersed power producing resources and may result in an overly conservative relay setting. Consider revising the standard to provide alternative options for setting the overcurrent element of a Protection System applied to an asynchronous generating unit and an Element utilized in the aggregation of dispersed power producing resources. 2. There is potential for Generator Owners to apply a pick up setting of the 50 element (i.e., instantaneous overcurrent) of a Protection System, which is not applicable to the standard, that is lower than the minimum pick up established by the standard for the 51 element (i.e., time delayed overcurrent). The 50 element is generally not used in the generator applications where the 51 element is found in the standard. In addition, there are some applications in which protective functions utilized measure and react to current but do not use ANSI device numbers. Consider revising the standard to address the inclusion or exclusion of the 50 element and other similar elements that may not use ANSI device numbers for the various overcurrent applications within Table 1.

[1] Refer to Institute of Electronics and Electrical Engineers (IEEE) Standard C37.2-2008 for American National Standards Institute (ANSI) device numbers.

SAR Information
3. There is potential for Generator Owners not to apply loadability margins to all load-responsive protective relays in Table 1 of PRC-025-1 under the "Application" column that may affect loadability. For example, the Application column from Table 1 (Options 4, 5, and 6): *"Asynchronous generating unit(s) (including inverter-based installations),* ***or*** *Elements utilized in the aggregation of dispersed power producing resources."* The above clause is separated by an "or" conjunction and may lead the Generator Owner to set one particular application and not the other. This may create a gap in achieving the goal of the standard when loadability margins are not applied to relays on certain Elements. Consider revising the standard to make it clear whether either or both of the listed Elements in the Application column of Options 1-6 must meet the criteria of the particular Option. For "Elements utilized in the aggregation of dispersed power producing resources", clarify that the standard is requiring an assessment from each generating source through the feeders and up through the interconnecting transmission line by adding a bulleted list. Alternatively, develop a section of Table 1 that specifically addresses relays applied on these Elements, making certain it is clear this statement applies to feeders in collection systems, and potentially then removing this statement from the current Options 1-6. 4. In the case of remote generating facilities that are electrically weak at its connection to the transmission network, the maximum Reactive Power required by the specific Table 1 Options is too high to be observed in any recoverable stressed condition. This is due to the system impedance (mainly line impedance) restricting the maximum Reactive Power output by the generator, no matter the generator characteristics. Lastly, applying the existing Table 1 Options for relay applications directional toward the Transmission system results in an overly conservative relay setting and could require reducing the backup protection coverage in order to comply with the stressed system condition anticipated by the standard. 5. The use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to "not trip" based on the criteria in Table 1. Clarify that multiple methods/curve types are acceptable so long as the applied protection does not trip the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating.

SAR Information
6. Miscellaneous items that may result in a lack of clarity in the standard, Attachment 1, and/or the Application Guidelines: a. It is not clear that the ANSI device numbers within the standard refer to the IEEE Standard C37.2-2008 reference document. Adding an appropriate reference will improve clarity. b. It is unclear when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based, and dispersed power producing resources. The description of what is classified as an asynchronous generator should be clarified. For example, the statement in Application Guidelines that "asynchronous generators… do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond" should be clarified/corrected or replaced since this category is intended to include inverter based, doubly-fed induction generator based, and induction generator based resources. Clarify the proper treatment of various resources. c. It is not clear that the phrase about unit capability "reported to the Transmission Planner" is a minimum criterion and that a greater unit capability is acceptable. Clarify that the Generator Owner may base settings on a capability higher than what is reported to the Transmission Planner. d. It is not clear that CB103 relay in Figure 1 of the Application Guidelines is applicable to the standard because the Application Guidelines only addresses a directional relay toward the generator plant as not being applicable; however, there are cases where CB103 would be applicable to the standard (e.g., non-directional relays). Provide clarity that would help prevent the overlooking of the CB103 relay as being applicable to the standard, including a potential revision to Figure 1.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The PRC-025-1 standard became effective on October 1, 2014 and has a phased implementation of five and seven years (i.e., 2019 or 2021) depending on the scope of work required by the Generator Owner. During the early stages of implementation, the above problems were revealed by industry. The scope of work will be to consider providing (1) an alternative loadability margin for dispersed power producing resources, (2) revision that includes or excludes 50 element for overcurrent applications, (3) clarification of the application of the Elements in Table 1 of PRC-025-1 for each option that has two applicable Elements separated by an "or" conjunction, (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the Transmission

SAR Information
system, (5) modify or eliminate the use of the term "pickup setting," and (6) miscellaneous consideration of clarifications to the standard, Attachment 1, and/or Application Guidelines.
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.)
1. Consider revising the PRC-025-1 standard concerning #1 above through the standards development process to provide a means to determine alternative loadability Options for Table 1 of the standard specific to dispersed power producing resources where there could be a manufacturer requirement or physical equipment limitation. Similar to the provisions already contained in the standard, consider methods that would eliminate the potential for non-compliance and/or a violation of manufacturer specifications. For example: (a) a provision could allow a margin consistent with the manufacturer's requirements or based on the limitation of the equipment; (b) a provision to allow the dispersed power producing resource output to be studied through simulation (e.g., similar to Options 1c and 2c) and the relays to be set with an appropriate margin determined through the standard development process; (c) a provision to exempt equipment with fixed limitations installed prior to the effective date of PRC-025-1 or other justifiable date; and/or (d) any other equally effective and efficient method to accomplish the goal.[2] 2. Consider revising the PRC-025-1 standard concerning #2 above to address the inclusion or exclusion of the 50 element (i.e., instantaneous overcurrent) of a Protection System, and other overcurrent type elements which may not utilize ANSI device numbers, with or without intentional time delay. Newer techniques in generator protection applications and differences in protective elements applied with different generation technologies may result in a gap due to non-traditional applications of generator overcurrent relays. 3. Consider revising the PRC-025-1 standard concerning #3 above through the standards development process to bring awareness and clarification that both of the Elements listed in the "Application" column of Table 1, Options 1-6 are to have loadability margins applied to the load-responsive protective relays.

[2] Any criteria revised in the standard concerning dispersed power producing resources should also be considered for Elements utilized in the aggregation of dispersed power producing resources, if separated from the dispersed power producing resources application of Table 1.

SAR Information
4. Consider revising the PRC-025-1 standard concerning #4 above through the standards development process to provide a means to determine alternative loadability Option(s) for Table 1 of the standard specific to relays directional toward the Transmission system. Similar to the provisions already contained in the standard, consider: (a) alternative Options for relay settings where the interconnecting transmission line impedance has a significant impact the maximum Reactive Power output of the generating facility and the associated relay settings, (b) the technical validity of the existing options in the presence of significant transmission line impedance between generation and the network, and/or (c) any other equally effective and efficient method to address the problem of significant line impedance effecting how phase protective relays are set not limit generator loadability while maintaining reliable protection of the BES for all fault conditions. 5. Consider revising Table 1 to modify or eliminate the use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to "not trip" based on the criteria in Table 1. Consider clarifying wherever necessary that multiple methods/curve types are acceptable so long as the applied protection does not trip the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating. 6. Miscellaneous considerations for the standard, Attachment 1, and/or Application Guidelines: a. Consider including a reference in the standard to clarify that the ANSI device numbers within the standard refers to IEEE Standard C37.2-2008 reference document. b. Consider whether it is clear and appropriate when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based and dispersed power producing resources. The description of what is classified as an asynchronous generator should be clarified. For example, Asynchronous generators do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond; therefore, are treated as "asynchronous" in Table 1. c. Consider clarifying the use of the phrase about unit capability "reported to the Transmission Planner" as being a minimum criterion and that a greater unit capability is acceptable.

SAR Information
d. Consider clarifying that CB103 relay in Figure 1 of the Application Guidelines is applicable to the standard and correct the figure to show CB103 as also possibly being subject to the standard. The Application Guidelines only addresses a directional relay and that non-directional relays would be applicable to the standard.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ 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.

Reliability Functions		
☒	Generator Owner	Owns and maintains generation facilities.
☐	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

Reliability and Market Interface Principles	
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
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
None.	

Related SARs	
SAR ID	Explanation
None.	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PRC-025-1 – Generator Relay Loadability		
Date Submitted:	August 25, 2016		
SAR Requester Information for #1			
Name:	Rich Quest		
Organization:	Midwest Reliability Organization		
Telephone:	(651) 855-1704	Email:	rp.quest@midwestreliability.org
SAR Requester Information for #2			
Name:	Jerry Thompson, E.I.T.		
Organization:	Kestrel Power Engineering		
Telephone:	(571) 293-1119	Email:	jerry@kestrelpower.com
SAR Requester Information for #3			
Name:	Joe DePoorter		
Organization:	Madison Gas & Electric		
Telephone:	(608) 252-1599	Email:	JDePoorter@mge.com

NERC

Request to propose a new or a revision to a Reliability Standard			
SAR Requester Information for #4			
Name:	Éric Loiselle, ing.		
Organization:	Hydro-Québec TransÉnergie		
Telephone:	(514) 879-4100	Email:	Loiselle.Eric2@hydro.qc.ca
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☒ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR proposes revising PRC-025-1 ~~for four~~the following specific problems. 1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed ~~generation~~power producing resources ~~(DGR).~~. 2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard. 3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s). 4. Prevent a lowering of dependability of protective relays directional toward the ~~transmission~~Transmission system at generating facilities that are remote to the transmission network. 5. Modify or eliminate the use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to “not trip” based on the criteria in Table 1. ~~4.~~6. Miscellaneous considerations for clarifications to the standard, Attachment 1, and/or Application Guidelines.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
Consider revising the PRC-025-1 standard through the standards development process to: (1) provide alternative loadability Options for Table 1 specific to ~~DGR~~dispersed power producing resources; (2) address the inclusion or exclusion of the 50 element[1] (i.e., instantaneous), (3) review Table 1 for proper application where there is more than one application for the available Option(s), ~~and~~ (4) provide alternative or additional Options for Table 1 specific to relay applications that are directional toward the ~~transmission~~Transmission system where the interconnecting transmission line impedance may be a factor in determining the maximum ~~reactive~~Reactive Power output of the generators and associated relay settings, (5) provide an alternative to the term "pickup setting" in Table 1 the will better align with the intent of the standard for relays to "not trip", and (6) provide clarity on identified miscellaneous items.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
This SAR proposes the need for revising PRC-025-1 for ~~four~~the following specific problems. 1. PRC-025-1, Table 1 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of ~~DGR~~dispersed power producing resources to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor. This may result in instances of non-compliance due manufacturer requirements or physical limitations of ~~DGR~~dispersed power producing resources and may result in an overly conservative relay setting. Consider revising the standard to provide alternative options for setting the overcurrent element of a Protection System applied to an asynchronous generating unit and an Element utilized in the aggregation of ~~DGR~~dispersed power producing resources. 2. There is potential for Generator Owners to apply a pick up setting of the 50 element (i.e., instantaneous overcurrent) of a Protection System, which is not applicable to the standard, that is lower than the minimum pick up established by the standard for the 51 element (i.e., time delayed overcurrent). The 50 element is generally not used in the generator applications where the 51 element is found in the standard. In addition, there are some applications in which protective functions utilized measure and react to current but do not use ANSI device numbers.

[1] Refer to Institute of Electronics and Electrical Engineers (IEEE) Standard C37.2-2008 for American National Standards Institute (ANSI) device numbers.

SAR Information
Consider revising the standard to address the inclusion or exclusion of the 50 element and other similar elements that may not use ANSI device numbers for the various overcurrent applications within Table 1. 3. There is potential for Generator Owners not to apply loadability margins to all load-responsive protective relays in Table 1 of PRC-025-1 under the "Application" column that may affect loadability. For example, the Application column from Table 1 (Options 4, 5, and 6): *"Asynchronous generating unit(s) (including inverter-based installations), **or** Elements utilized in the aggregation of dispersed power producing resources."* The above clause is separated by an "or" conjunction and may lead the Generator Owner to set one particular application and not the other. This may create a gap in achieving the goal of the standard when loadability margins are not applied to relays on certain Elements. Consider revising the standard to make it clear whether either or both of the listed Elements in the Application column of Options 1-6 must meet the criteria of the particular Option. For "Elements utilized in the aggregation of dispersed power producing resources", clarify that the standard is requiring an assessment from each generating source through the feeders and up through the interconnecting transmission line by adding a bulleted list. Alternatively, develop a section of Table 1 that specifically addresses relays applied on these Elements, making certain it is clear this statement applies to feeders in collection systems, and potentially then removing this statement from the current Options 1-6. 4. In the case of remote generating facilities that are electrically weak at its connection to the transmission network, the maximum ~~reactive power~~Reactive Power required by the specific Table 1 Options is too high to be observed in any recoverable stressed condition. This is due to the system impedance (mainly line impedance) restricting the maximum ~~reactive power~~Reactive Power output by the generator, no matter the generator characteristics. Lastly, applying the existing Table 1 Options for relay applications directional toward the ~~transmission~~Transmission system results in an overly conservative relay setting and could require reducing the backup protection coverage in order to comply with the stressed system condition anticipated by the standard. 5. The use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to "not trip" based on the criteria in Table 1. Clarify that multiple methods/curve types are acceptable so long as the applied protection does not trip the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of

SAR Information
blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating. 6. Miscellaneous items that may result in a lack of clarity in the standard, Attachment 1, and/or the Application Guidelines: a. It is not clear that the ANSI device numbers within the standard refer to the IEEE Standard C37.2-2008 reference document. Adding an appropriate reference will improve clarity. b. It is unclear when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based, and dispersed power producing resources. The description of what is classified as an asynchronous generator should be clarified. For example, the statement in Application Guidelines that "asynchronous generators… do not have excitation systems and will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond" should be clarified/corrected or replaced since this category is intended to include inverter based, doubly-fed induction generator based, and induction generator based resources. Clarify the proper treatment of various resources. c. It is not clear that the phrase about unit capability "reported to the Transmission Planner" is a minimum criterion and that a greater unit capability is acceptable. Clarify that the Generator Owner may base settings on a capability higher than what is reported to the Transmission Planner. ~~a.~~d. It is not clear that CB103 relay in Figure 1 of the Application Guidelines is applicable to the standard because the Application Guidelines only addresses a directional relay toward the generator plant as not being applicable; however, there are cases where CB103 would be applicable to the standard (e.g., non-directional relays). Provide clarity that would help prevent the overlooking of the CB103 relay as being applicable to the standard, including a potential revision to Figure 1.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The PRC-025-1 standard became effective on October 1, 2014 and has a phased implementation of five and seven years (i.e., 2019 or 2021) depending on the scope of work required by the Generator Owner. During the early stages of implementation, the above ~~four~~ problems were revealed by industry. The scope of work will be to consider providing (1) an alternative loadability margin for ~~DGR~~dispersed power producing resources, (2) revision that includes or excludes 50 element for overcurrent applications, (3)

SAR Information
clarification of the application of the Elements in Table 1 of PRC-025-1 for each option that has two applicable Elements separated by an "or" conjunction, ~~and~~ (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the ~~transmission.~~Transmission system, (5) modify or eliminate the use of the term "pickup setting," and (6) miscellaneous consideration of clarifications to the standard, Attachment 1, and/or Application Guidelines.
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.)
1. Consider revising the PRC-025-1 standard concerning #1 above through the standards development process to provide a means to determine alternative loadability Options for Table 1 of the standard specific to ~~DRG equipment~~dispersed power producing resources where there could be a manufacturer requirement or physical equipment limitation. Similar to the provisions already contained in the standard, consider methods that would eliminate the potential for non-compliance and/or a violation of manufacturer specifications. For example: (a) a provision could allow a margin consistent with the manufacturer's requirements or based on the limitation of the equipment; (b) a provision to allow the ~~DRG~~dispersed power producing resource output to be studied through simulation (e.g., similar to Options 1c and 2c) and the relays to be set with an appropriate margin determined through the standard development process; (c) a provision to exempt equipment with fixed limitations installed prior to the effective date of PRC-025-1 or other justifiable date; and/or (d) any other equally effective and efficient method to accomplish the goal.[2] 2. Consider revising the PRC-025-1 standard concerning #2 above to address the inclusion or exclusion of the 50 element (i.e., instantaneous overcurrent) of a Protection System, and other overcurrent type elements which may not utilize ANSI device numbers, with or without intentional time delay. Newer techniques in generator protection applications and differences in protective elements applied with different generation technologies may result in a gap due to non-traditional applications of generator overcurrent relays.

[2] Any criteria revised in the standard concerning dispersed power producing resources should also be considered for Elements utilized in the aggregation of dispersed power producing resources, if separated from the dispersed power producing resources application of Table 1.

SAR Information
3. Consider revising the PRC-025-1 standard concerning #3 above through the standards development process to bring awareness and clarification ~~whether either or~~that both of the Elements listed in the "Application" column of Table 1, Options 1-6 are to have loadability margins applied to the load-responsive protective relays. 4. Consider revising the PRC-025-1 standard concerning #4 above through the standards development process to provide a means to determine alternative loadability Option(s) for Table 1 of the standard specific to relays directional toward the ~~transmission~~Transmission system. Similar to the provisions already contained in the standard, consider: (a) alternative Options for relay settings where the interconnecting transmission line impedance has a significant impact the maximum ~~reactive~~Reactive Power output of the generating facility and the associated relay settings, (b) the technical validity of the existing options in the presence of significant transmission line impedance between generation and the network, and/or (c) any other equally effective and efficient method to address the problem of significant line impedance effecting how phase protective relays are set not limit generator loadability while maintaining reliable protection of the BES for all fault conditions. 5. Consider revising Table 1 to modify or eliminate the use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to "not trip" based on the criteria in Table 1. Consider clarifying wherever necessary that multiple methods/curve types are acceptable so long as the applied protection does not trip the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating. 6. Miscellaneous considerations for the standard, Attachment 1, and/or Application Guidelines: a. Consider including a reference in the standard to clarify that the ANSI device numbers within the standard refers to IEEE Standard C37.2-2008 reference document. b. Consider whether it is clear and appropriate when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based and dispersed power producing resources. The description of what is classified as an asynchronous generator should be clarified. For example, Asynchronous generators do not have excitation systems and will not respond to a disturbance with the same

SAR Information
magnitude of apparent power that a synchronous generator will respond; therefore, are treated as "asynchronous" in Table 1. c. Consider clarifying the use of the phrase about unit capability "reported to the Transmission Planner" as being a minimum criterion and that a greater unit capability is acceptable. ~~a.~~d. Consider clarifying that CB103 relay in Figure 1 of the Application Guidelines is applicable to the standard and correct the figure to show CB103 as also possibly being subject to the standard. The Application Guidelines only addresses a directional relay and that non-directional relays would be applicable to the standard.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ 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).

Reliability Functions		
☒	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.
☐	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.

Reliability and Market Interface Principles	
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 with that standard.	Yes
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
None.	

Related SARs	
SAR ID	Explanation
None.	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2016-04 Modifications to PRC-025-1
Standards Authorization Request

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2016-04 Modifications to PRC-025-1 (Generator Relay Loadability) Standards Authorization Request (SAR)**. The electronic form must be submitted by **8 p.m. Eastern, Monday, April 3, 2017.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at (404) 446-9689.

Background

Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, four specific issues have been identified in Draft 1 of the SAR that was posted for industry comment from September 16, 2016 through October 18, 2016.

Summary

Draft 1 of the SAR proposed that the PRC-025-1 standard be revised to provide: (1) an alternative loadability margin for dispersed generation resources; (2) an inclusion or exclusion of the 50 overcurrent element, (3) clarification on whether the Elements in the “Application” column of Table 1 of PRC-025-1 that have two applications separated by an “or” conjunction should both be included or may one or the other be selected; and (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the transmission. This scoping has not change substantively.

In addition to the above four items, Draft 2 of the SAR proposes the following items in summary form: (5) Modify or eliminate the use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to “not trip” based on the criteria in Table 1; and (6) Miscellaneous clarifications, which include:

a. Consider the use of references to the American National Standards Institute (ANSI) device numbers given that some equipment may not use traditional nomenclature.

b. Consider whether it is clear and appropriate when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based and dispersed power producing resources.

c. Clarify that a high unit capability may be used other than the value “reported to the Transmission Planner,” which is a minimum capability.

d. Clarify that CB103 relay is applicable to the standard.

Questions

1. Do you agree with the revisions to Items 1-4 in response to comments from industry stakeholders on draft 1 of the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the additions of Items 5 and 6 in response to comments and discussions by the SAR drafting team? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.

   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

Standards Announcement

Project 2016-04 Modifications to PRC-025-1 Standards Authorization Request

Informal Comment Period Open through April 3, 2017

Now Available

A 15-day informal comment period for the **Project 2016-04 Modifications to PRC-025-1 Standards Authorization Request (SAR)**, is open through **8 p.m. Eastern, Monday, April 3, 2017**.

Commenting
Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the Standards Balloting & Commenting System due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The drafting team will consider all comments received and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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

Comment Report

Project Name: 2016-04 Modifications to PRC-025-1 | Standards Authorization Request

Comment Period Start Date: 3/20/2017

Comment Period End Date: 4/3/2017

Associated Ballots:

There were 16 sets of responses, including comments from approximately 69 different people from approximately 55 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions to Items 1-4 in response to comments from industry stakeholders on draft 1 of the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.

2. Do you agree with the additions of Items 5 and 6 in response to comments and discussions by the SAR drafting team? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Mark Ringhausen	Mark Ringhausen	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC

					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE

1. Do you agree with the revisions to Items 1-4 in response to comments from industry stakeholders on draft 1 of the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Review Group recommends that the drafting team provides clarity to why the term "Transmission" is capitalized in the phrase "Transmission system," while the same term is not capitalized in the phrase "transmission network" which is associated with proposed language pertaining to item 4 (page 2) of the Standard Authorization Request (SAR). The review group has a concern that there are some inconsistencies in the combination and capitalization of particular NERC defined terms and phrases.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

Please see response to #3.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF agrees with items 1 – 4 but is concerned about confusing individual collector circuits with less than 75 MVA of aggregate individual dispersed power producing resources with the concept of a common mode design condition that could result in the loss of 75 MVA or more of aggregate generation at a single generating Facility.

The NSRF suggests that the SAR clarify that the basis of inclusion for individual BES generators (individual wind turbines or solar panels) or individual collectors is the common mode loss of 75 MVA or more of generation.

To support the above basis that its not individual BES generators (Elements) that are of concern, that it is common mode outage that results in the loss of 75 MVA or more of generating Elements at a BES generating Facility, the NSRF suggests that the NERC definitions of Element and Facilities be clarified. NERC Elements should refer to individual BES generators and NERC Facilities should refer to aggregating more that 75 MVA of BES generating Elements at a single Facility.

NERC BES Element Definition: Any electrical device with terminals that may be connected to other electrical devices such as an individual generator or power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC BES Facility Definition: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a a single shaft unit of greater than 20 MVA or aggregate individual dispersed power producing resources of more than 75 MVA, a shunt compensator, transformer, etc.)

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 3,5

Answer	Yes
Document Name	

Comment

AEP has no objections to the revisions of Items 1 through 4 in the draft SAR.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

We agree with the proposal to provide clarification and align better with the intent of the standard for relays to "not trip" under load.	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
When applicable, would definite time elements (50DT) be addressed similar to instantaneous 50 elements?	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Connie Lowe - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the additions of Items 5 and 6 in response to comments and discussions by the SAR drafting team? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Please see response to #3.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
We agree with the proposal to provide clarification and align better with the intent of the standard for relays to "not trip" under load.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy suggests additional language be added to item c. of the Miscellaneous Items. As written, not entirely clear what the issue is, and what is meant by a “minimum criterion” in relation to the standard. More information about what the issue/concern is with this phrase would be helpful to understand the necessity of the revision.	
Likes 0	
Dislikes 0	
Response	
Connie Lowe - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
On item #6 , the language currently reads: "Clarify that a high unit capability may be used". Dominion suggests additional language in the detailed description under item 6(b)stating that “the generator nameplate rating can also be used for the real power output.” in the final recommendation.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
On item #6 , the language currently reads: "Clarify that a high unit capability may be used". Dominion suggests additional language in the detailed description under item 6(b)stating that “the generator nameplate rating can also be used for the real power output.” in the final recommendation.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	
Document Name	
Comment	
While AEP has no objections to the inclusion of Items 5 and 6 into the draft SAR, we seek clarity on 6c as the proposed language could cause a communication barrier between the TP and GO fuctions regarding "reported to the Transmission Planner". For example, what specific reliability concern is it attempting to address, and exactly what is driving its proposed inclusion in the SAR?	
Likes 0	
Dislikes 0	
Response	

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

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
We have no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
The review group recommends capitalizing the term "system" in the phrase "Transmission system" that's associated with the proposed language (on page 2, 4, and 7) of the SAR. The group's perspective is that both terms are defined in the NERC Glossary of Terms. Also, we recommend the drafting team consider collaborative efforts with The Alignment of Terms Drafting Team. The Alignment of Terms Drafting Team can provide some useful insight on how to address the inconsistencies of the combination and capitalization of particular NERC defined terms and phrases like "Transmission system." Additionally, we recommend that the drafting team provides clarity on the meaning of the two phrases "Transmission system" and "transmission network."	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	
Document Name	
Comment	
We support the SAR for Project 2016-04 Modifications to PRC-025-1.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	

The BES definition states that the individual resource should be included, however, many things within the way the standard is written can be argued otherwise. The first example is the wording taken directly from the standard :

“Asynchronous generating unit(s) (including inverter based installations), or Elements

utilized in the aggregation of dispersed power producing resources.”

The OR referenced in Attachment 1, Table, (*leading to Elements utilized in the aggregation of dispersed power producing re-sources)* offer a choice which could eliminate the obligation to analyze down to the turbine level.

Another point is that the device within the wind turbine isn’t a standard relay element 51 or 51V-R. The device in the turbine is a low voltage molded case circuit breaker. Even more specifically, the device ANSI representation is a 52 – AC Circuit Breaker. What makes this even more frustrating is that generator owners and engineers within have no control of how these wind turbines were designed and commissioned by the OEM. We did not provide the settings nor do we ever intend to change them from what the OEM originally placed.

The final point to make, if entities are required to comply down to the turbine level main circuit breaker then there will be many cases that the breakers cannot be adjusted to a current that is over 130% nameplate MVA rating.   The Long time pickup is typically set slightly above nameplate with a “long” time delay (example 10 seconds). This is a perfectly appropriate way to operate the wind turbine as there are other faster operating over current elements enabled on the same breaker (Short time and Instantaneous) that will protect for more severe faults. The element of time delay isn’t specified in this standard which also adds issues.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	

(1) We believe the authors need to identify that Requirement R1 is only applicable to the small subset of GOs, TOs, and DPs that apply load-responsive protective relays at the Element terminals listed under the standard's applicability section. We recommend instructing the SDT to change the applicability of the requirement to "Responsible Entity" or "Functional Entity".

(2) We question the overall urgency identified within the SAR, particularly since the current implementation plan does not require 100% compliance until 2019 or 2021 for retrofits. If there are concerns over current regional practices that exist, we believe pursing interpretations or regional variances may be a better alternative.

(3) We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name: 2016-04 Modifications to PRC-025-1 | Standards Authorization Request
Comment Period Start Date: 3/20/2017
Comment Period End Date: 4/3/2017

There were 16 sets of responses, including comments from approximately 69 different people from approximately 55 companies representing the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Questions

1. **Do you agree with the revisions to Items 1-4 in response to comments from industry stakeholders on draft 1 of the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.**
2. **Do you agree with the additions of Items 5 and 6 in response to comments and discussions by the SAR drafting team? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.**
3. **If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.**

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Mark Ringhausen	Mark Ringhausen	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Quintin Lee	Eversource Energy	1	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						System Operator		
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE

1. *Do you agree with the revisions to Items 1-4 in response to comments from industry stakeholders on draft 1 of the SAR? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.*	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Review Group recommends that the drafting team provides clarity to why the term "Transmission" is capitalized in the phrase "Transmission system," while the same term is not capitalized in the phrase "transmission network" which is associated with proposed language pertaining to item 4 (page 2) of the Standard Authorization Request (SAR). The review group has a concern that there are some inconsistencies in the combination and capitalization of particular NERC defined terms and phrases.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. When "Transmission system" is used in the SAR, an emphasis is placed on the NERC defined term on how it is used within the standard and requirements. When it is lowercase as in "transmission network," no association with the NERC defined term is intended and the general understanding of the term or phrase would be applied. For example, note the consistency with PRC-023-4 (Transmission Loadability) where "Transmission system" is used in the Applicability section and "transmission system" is used in Requirement R1. No change was made to the SAR.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Please see response to #3.	

Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF agrees with items 1 – 4 but is concerned about confusing individual collector circuits with less than 75 MVA of aggregate individual dispersed power producing resources with the concept of a common mode design condition that could result in the loss of 75 MVA or more of aggregate generation at a single generating Facility.

The NSRF suggests that the SAR clarify that the basis of inclusion for individual BES generators (individual wind turbines or solar panels) or individual collectors is the common mode loss of 75 MVA or more of generation.

To support the above basis that its not individual BES generators (Elements) that are of concern, that it is common mode outage that results in the loss of 75 MVA or more of generating Elements at a BES generating Facility, the NSRF suggests that the NERC definitions of Element and Facilities be clarified. NERC Elements should refer to individual BES generators and NERC Facilities should refer to aggregating more that 75 MVA of BES generating Elements at a single Facility.

NERC BES Element Definition: Any electrical device with terminals that may be connected to other electrical devices such as an individual generator or power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC BES Facility Definition: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a a single shaft unit of greater than 20 MVA or aggregate individual dispersed power producing resources of more than 75 MVA, a shunt compensator, transformer, etc.)

Likes 0	
Dislikes 0	
Response	

1. Thank you for your comment. Regarding inclusion of collector circuits in dispersed power producing resources, the SAR team notes the following:
   a. While 75 MVA aggregate capacity is utilized when determining whether a site meets the inclusion I4 criteria from the Bulk Electric System definition, this measurement is not intended to be utilized as a performance criteria or threshold within a standard. The goal of PRC-025-1 is to ensure that generating resources which are classified as Bulk Electric System generators (through whichever inclusions, bright-line criteria, etc.) have protection applied which allows those generators to provide the full amount of any dynamic (short term) and steady state real and reactive support to the transmission system for which these generators are capable (whatever that amount may be), not to ensure that a loss of 75 MVA or more of generation is avoided.
   b. Inclusion of collector system feeders within the applicability of PRC-025-1 was always intended, but was not clear. Clarifying this is one of the goals of the SAR.
   c. Based on the above factors, the SAR team believes changes to the BES Element and BES Facility definitions are not necessary, and believes the Applicability criteria within the standard are correct. No change was made to the SAR.

Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP has no objections to the revisions of Items 1 through 4 in the draft SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
We agree with the proposal to provide clarification and align better with the intent of the standard for relays to "not trip" under load.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
When applicable, would definite time elements (50DT) be addressed similar to instantaneous 50 elements?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard does not contemplate consideration of setting time delays, time dials, etc. Within the context of ANSI device numbers, devices with suffixes are considered sub-functions of the parent device number. It is the current intent of the SAR to clarify that the instantaneous overcurrent elements of all types should be included and considered (also including devices that do not use ANSI device numbers but behave similarly), regardless of the time element applied. Consequently, a 50DT would be treated similar to a 50 element. No change was made to the SAR.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Connie Lowe - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the additions of Items 5 and 6 in response to comments and discussions by the SAR drafting team? If not, please explain why you do not agree and provide specific detail referencing the applicable SAR item that would make it acceptable to you.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Please see response to #3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, response is found in #3.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Answer	Yes
Document Name	
Comment	
We agree with the proposal to provide clarification and align better with the intent of the standard for relays to "not trip" under load.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy suggests additional language be added to item c. of the Miscellaneous Items. As written, not entirely clear what the issue is, and what is meant by a "minimum criterion" in relation to the standard. More information about what the issue/concern is with this phrase would be helpful to understand the necessity of the revision.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The capability reported to the Transmission Planner is the minimum capability on which protection settings should be based. It should be acceptable to base protection settings on a higher capability. It is not required that protection settings be modified when the capability reported to the Transmission Planner may be lower to reflect seasonal variations or other deratings. In real-time operations, ambient conditions and other factors may drive greater maximum capability than what is "reported to the Transmission Planner" for generators with certain types of prime movers. No change was made to the SAR.	
Connie Lowe - Dominion - Dominion Resources, Inc. - 3,5,6	

Answer	Yes
Document Name	
Comment	
On item #6, the language currently reads: "Clarify that a high unit capability may be used". Dominion suggests additional language in the detailed description under item 6(b) stating that "the generator nameplate rating can also be used for the real power output." in the final recommendation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR team believes adding additional detail, such as, "the generator nameplate rating can also be used for the real power output" may increase confusion. The capability reported to the Transmission Planner is the minimum capability on which protection settings should be based. It should be acceptable to base protection settings on a higher capability, which could be any higher value including the nameplate value of the generator unit. It is not required that protection settings be modified when the capability reported to the Transmission Planner may be lower to reflect seasonal variations or other deratings. In real-time operations, ambient conditions and other factors may drive greater maximum capability than what is "reported to the Transmission Planner" for generators with certain types of prime movers. No change was made to the SAR.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
On item #6 , the language currently reads: "Clarify that a high unit capability may be used". Dominion suggests additional language in the detailed description under item 6(b)stating that "the generator nameplate rating can also be used for the real power output." in the final recommendation.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SAR team believes adding additional detail, such as, "the generator nameplate rating can also be used for the real power output" may increase confusion. The capability reported to the Transmission Planner is the minimum capability on which protection settings should be based. It should be acceptable to base protection settings on a higher capability, which could be any higher value including the nameplate value of the generator unit. It is not required that protection settings be modified when the capability reported to the Transmission Planner may be lower to reflect seasonal variations or other deratings. In real-time operations, ambient conditions and other factors may drive greater maximum capability than what is "reported to the Transmission Planner" for generators with certain types of prime movers. No change was made to the SAR.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	
Document Name	
Comment	
While AEP has no objections to the inclusion of Items 5 and 6 into the draft SAR, we seek clarity on 6c as the proposed language could cause a communication barrier between the TP and GO fuctions regarding “reported to the Transmission Planner”. For example, what specific reliability concern is it attempting to address, and exactly what is driving its proposed inclusion in the SAR?	
Likes 0	
Dislikes 0	

Response
Thank you for your comment. The capability reported to the Transmission Planner is the minimum capability on which protection settings should be based. It should be acceptable to base protection settings on a higher capability. It is not required that protection settings be modified when the capability reported to the Transmission Planner may be lower to reflect seasonal variations or other deratings. In real-time operations, ambient conditions and other factors may drive greater maximum capability than what is "reported to the Transmission Planner" for generators with certain types of prime movers. No change was made to the SAR.

3. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
We have no additional comments at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	

Comment	
The review group recommends capitalizing the term "system" in the phrase "Transmission system**"** that's associated with the proposed language (on page 2, 4, and 7) of the SAR. The group's perspective is that both terms are defined in the NERC Glossary of Terms. Also, we recommend the drafting team consider collaborative efforts with The Alignment of Terms Drafting Team. The Alignment of Terms Drafting Team can provide some useful insight on how to address the inconsistencies of the combination and capitalization of particular NERC defined terms and phrases like "Transmission system.**"** Additionally, we recommend that the drafting team provides clarity on the meaning of the two phrases "Transmission system" and "transmission network**.**"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The defined term "System" was not used in the PRC-025-1 standard because it would unintentionally include distribution. The SAR drafting team does not agree that the term "System" should be capitalized to reference the NERC Glossary[1] as it would change the intent and applicable facilities. The SAR team additionally notes that use of the phrase "Transmission system" is consistent with PRC-023-4. No change was made to the SAR.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	
Document Name	
Comment	
We support the SAR for Project 2016-04 Modifications to PRC-025-1.	
Likes 0	
Dislikes 0	
Response	

[1] Glossary of Terms Used in NERC Reliability Standards (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf)

Thank you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	

The BES definition states that the individual resource should be included, however, many things within the way the standard is written can be argued otherwise. The first example is the wording taken directly from the standard :

"Asynchronous generating unit(s) (including inverter-based installations), **or** Elements utilized in the aggregation of dispersed power producing resources."

The OR referenced in Attachment 1, Table, (*leading to Elements utilized in the aggregation of dispersed power producing re-sources)* offer a choice which could eliminate the obligation to analyze down to the turbine level.

Another point is that the device within the wind turbine isn't a standard relay element 51 or 51V-R. The device in the turbine is a low voltage molded case circuit breaker. Even more specifically, the device ANSI representation is a 52 – AC Circuit Breaker. What makes this even more frustrating is that generator owners and engineers within have no control of how these wind turbines were designed and commissioned by the OEM. We did not provide the settings nor do we ever intend to change them from what the OEM originally placed.

The final point to make, if entities are required to comply down to the turbine level main circuit breaker then there will be many cases that the breakers cannot be adjusted to a current that is over 130% nameplate MVA rating.   The Long time pickup is typically set slightly above nameplate with a "long" time delay (example 10 seconds). This is a perfectly appropriate way to operate the wind turbine as there are other faster operating over current elements enabled on the same breaker (Short time and Instantaneous) that will protect for more severe faults. The element of time delay isn't specified in this standard which also adds issues.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The comment raised about the "OR" condition is the specific issue the SAR intends to resolve by addressing the "OR" conjunction used in the Applicability column of Table 1. This is addressed by item 3 in the SAR. No change made to the SAR. No change was made to the SAR.

The comment raised about the use of ANSI device numbers is an issue the SAR is addressing. Differences in ANSI device numbering is most apparent in low voltage protection of the dispersed power producing resources. See item 2 in the SAR concerning ANSI device numbering. No change was made to the SAR.

The comment raised about adjusting the resource breakers is an issue the SAR intends to resolve by providing one or more alternatives to the current Table 1 criteria for setting relays. See item 1 in the SAR concerning instances where manufacturer requirements or physical limitations of dispersed power producing resources and may result in an overly conservative relay setting. No change was made to the SAR.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
(1) We believe the authors need to identify that Requirement R1 is only applicable to the small subset of GOs, TOs, and DPs that apply load-responsive protective relays at the Element terminals listed under the standard's applicability section. We recommend instructing the SDT to change the applicability of the requirement to "Responsible Entity" or "Functional Entity". (2) We question the overall urgency identified within the SAR, particularly since the current implementation plan does not require 100% compliance until 2019 or 2021 for retrofits. If there are concerns over current regional practices that exist, we believe pursing interpretations or regional variances may be a better alternative. (3) We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
1. The SAR drafting team does not agree that changing the applicable entities in Requirement R1 to "Responsible Entity" or "Functional Entity" adds any additional clarity. No change was made to the SAR. 2. There are no needs for any variances. The issues raised in the SAR impact a small number of entities and facilities; however, NERC is mindful of the time needed for industry input, approval, and subsequent regulatory approval prior to the set enforcement dates. 3. Thank you for your comments.	

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan
6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

8. Compliance Monitoring Process

8.1. 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.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8.2. 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 Compliance Enforcement Authority (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 Generator Owner, Transmission Owner, and Distribution Provider 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, "Considerations for Power Plant and Transmission System Protection Coordination," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.
Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative

assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly

[3] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	Setting Criteria
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer[5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer[6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer[7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[4]	**Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer[8]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer[9]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

A different application starts on the next page

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.
[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[4]</th><th>Setting Criteria</th></tr>
<tr><td rowspan="3">Unit auxiliary transformer(s) (UAT)</td><td rowspan="3">Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.</td><td>13a</td><td>1.0 per unit of the winding nominal voltage of the unit auxiliary transformer</td><td>The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>13b</td><td>Unit auxiliary transformer bus voltage corresponding to the measured current</td><td>The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td rowspan="4">Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to synchronous generators</td><td rowspan="3">Phase distance relay (e.g., 21) – directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of line[11]</td><td>14a</td><td>0.85 per unit of the line nominal voltage at the relay location</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>14b</td><td>Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line and/or phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer and remote end of the line[12]	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer and on the remote end of line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer and on the remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer and on the remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[16] If the relay is installed on the generator-side of the GSU transformer use Option 12.

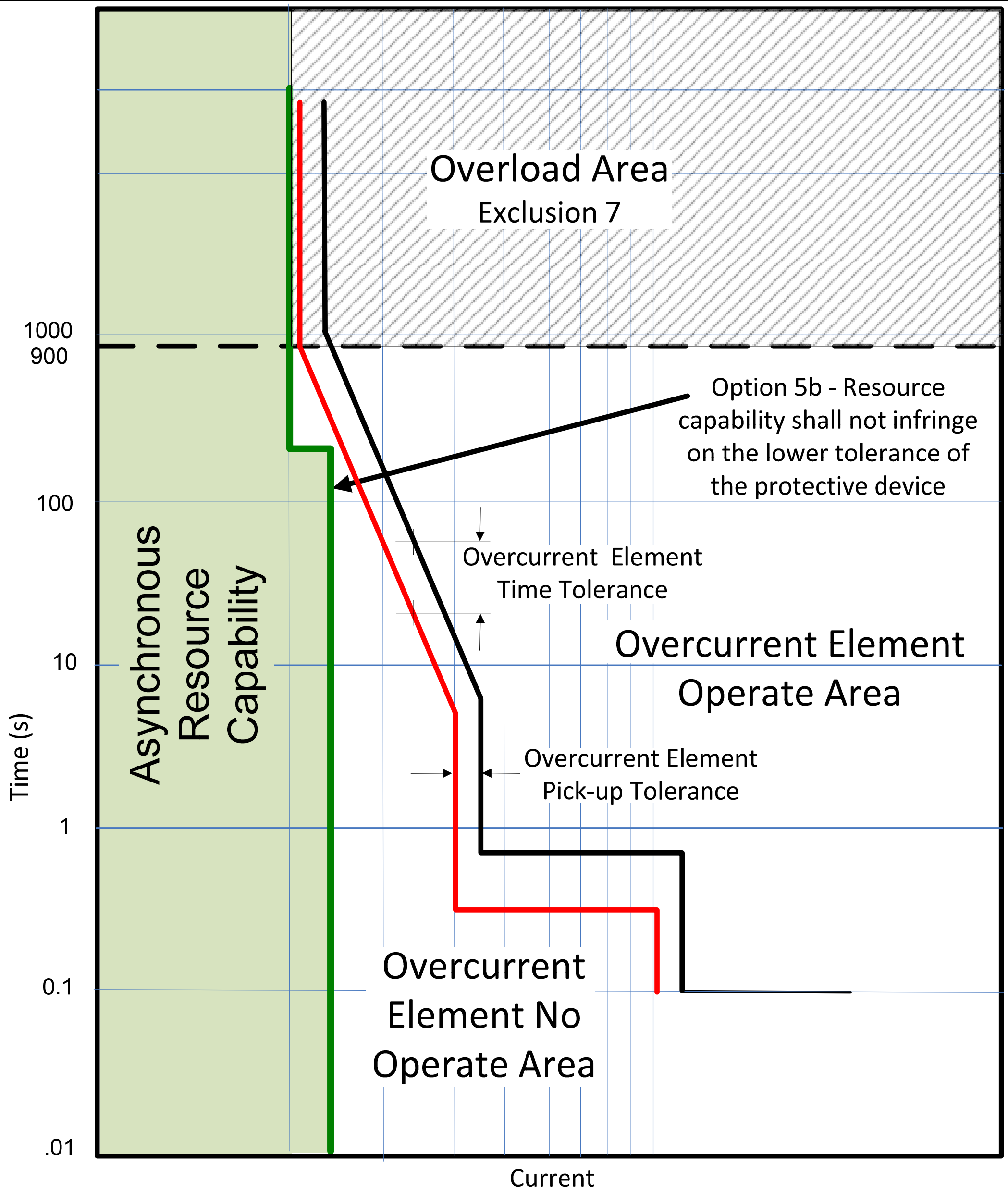


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

---

[17] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

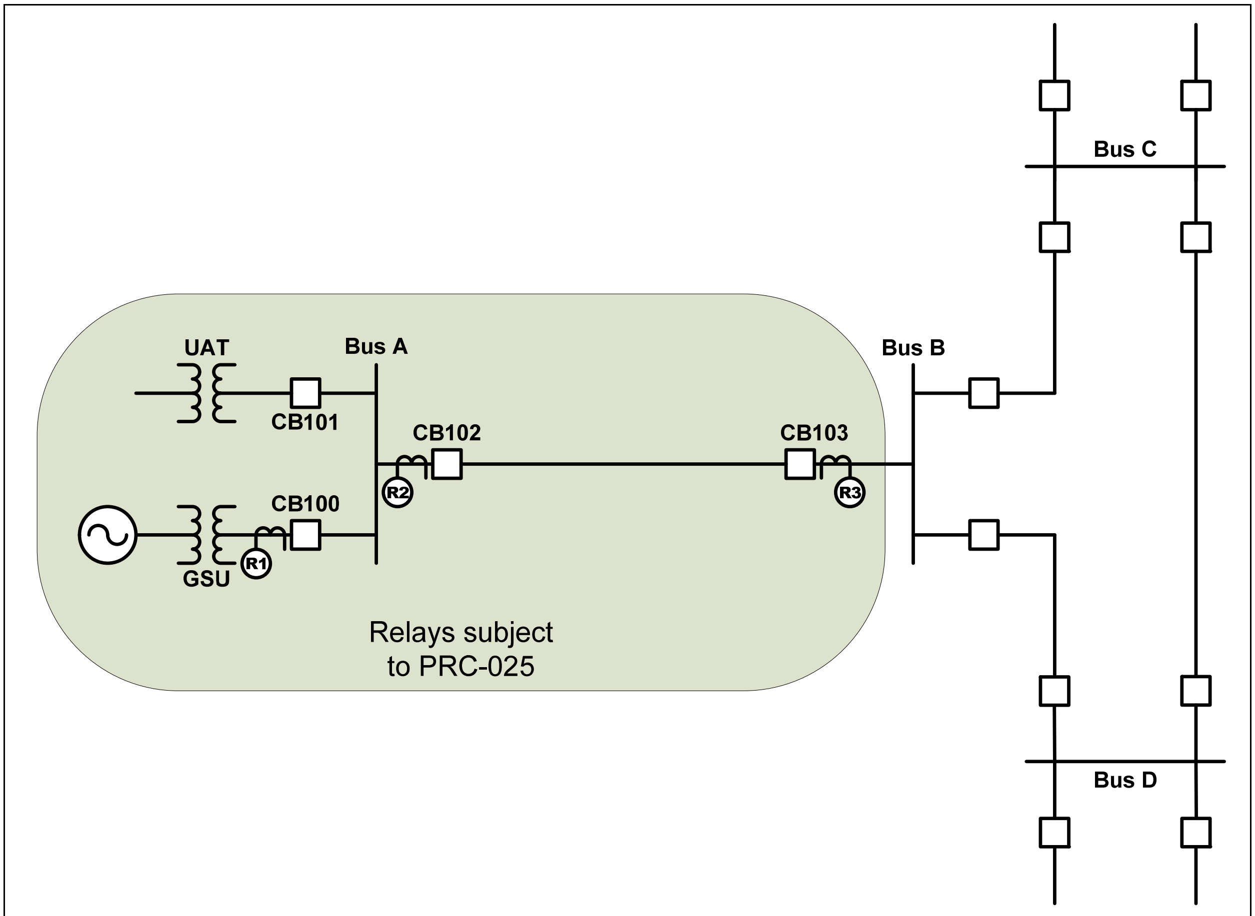


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

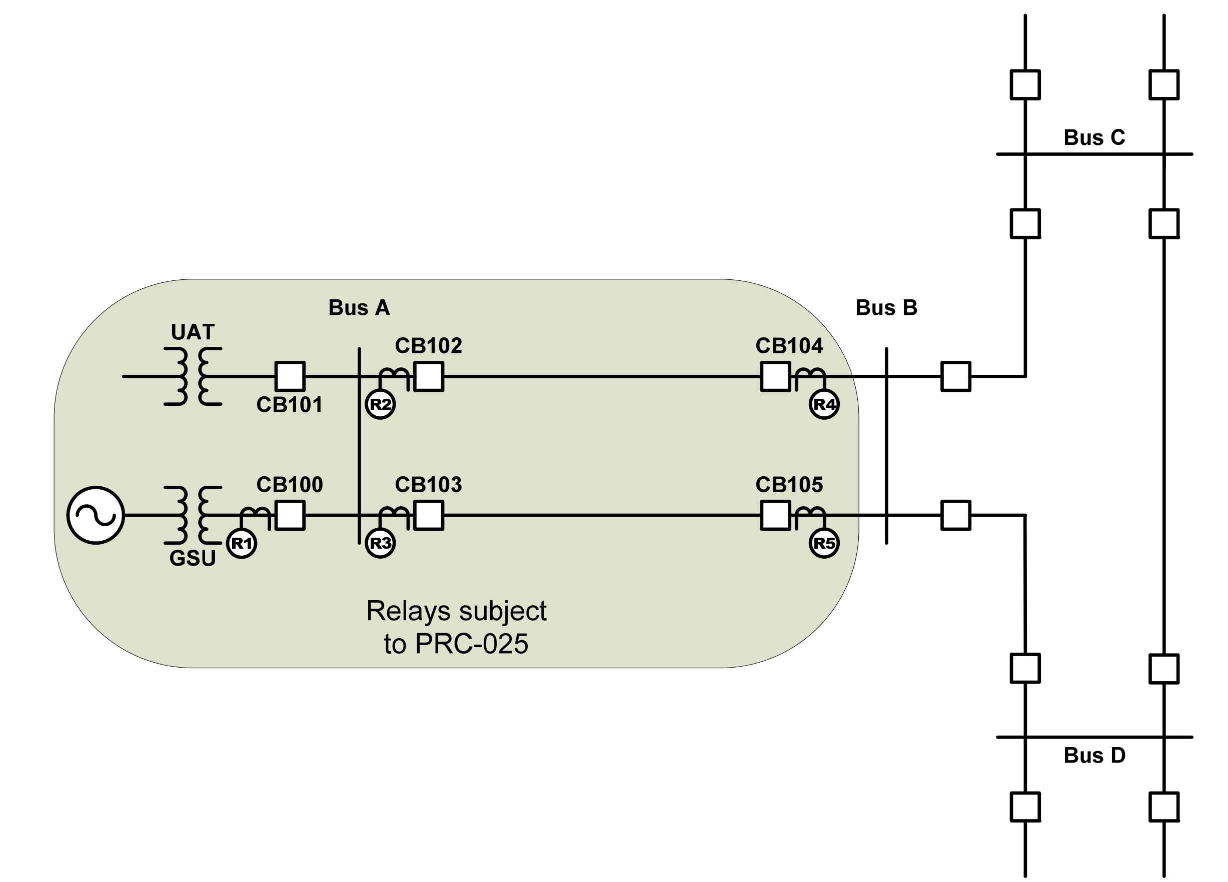


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

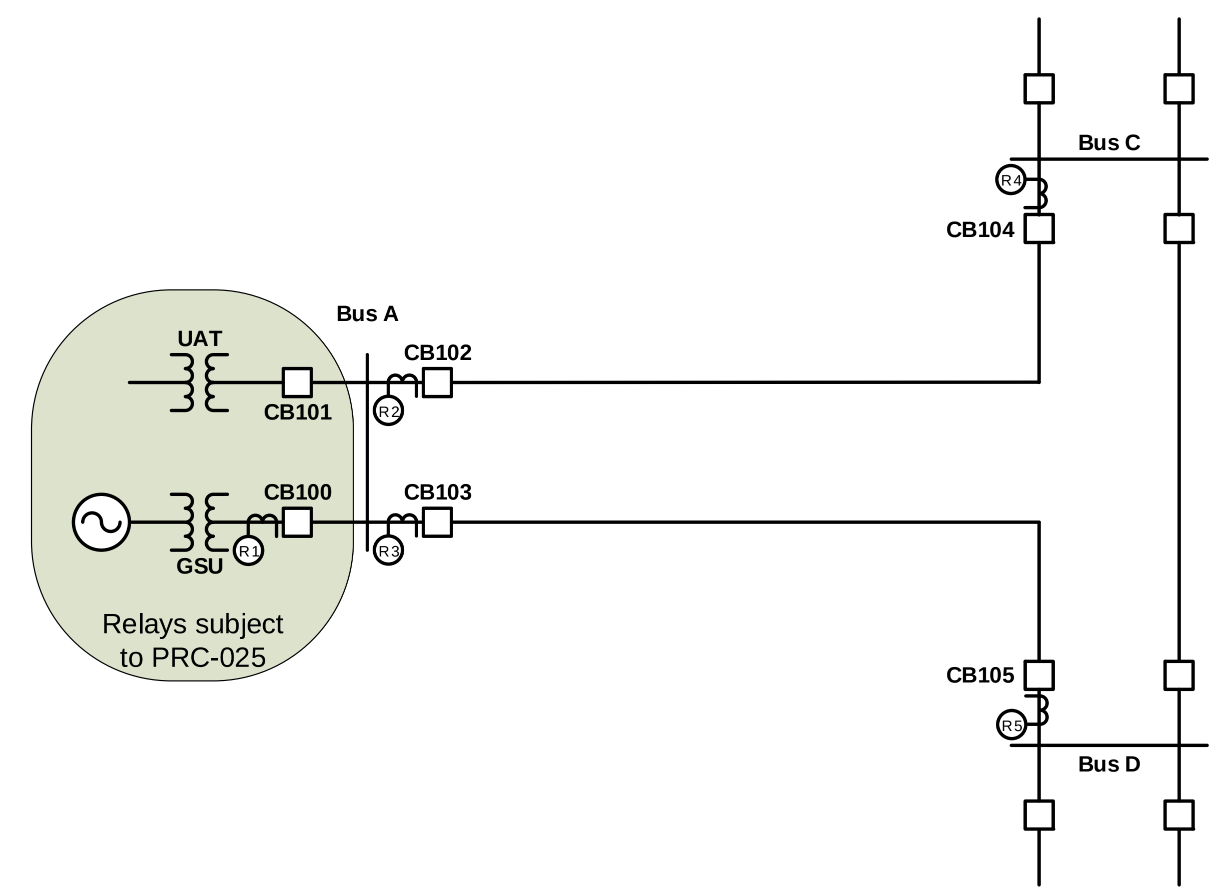


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the*

> *delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differs from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differs from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

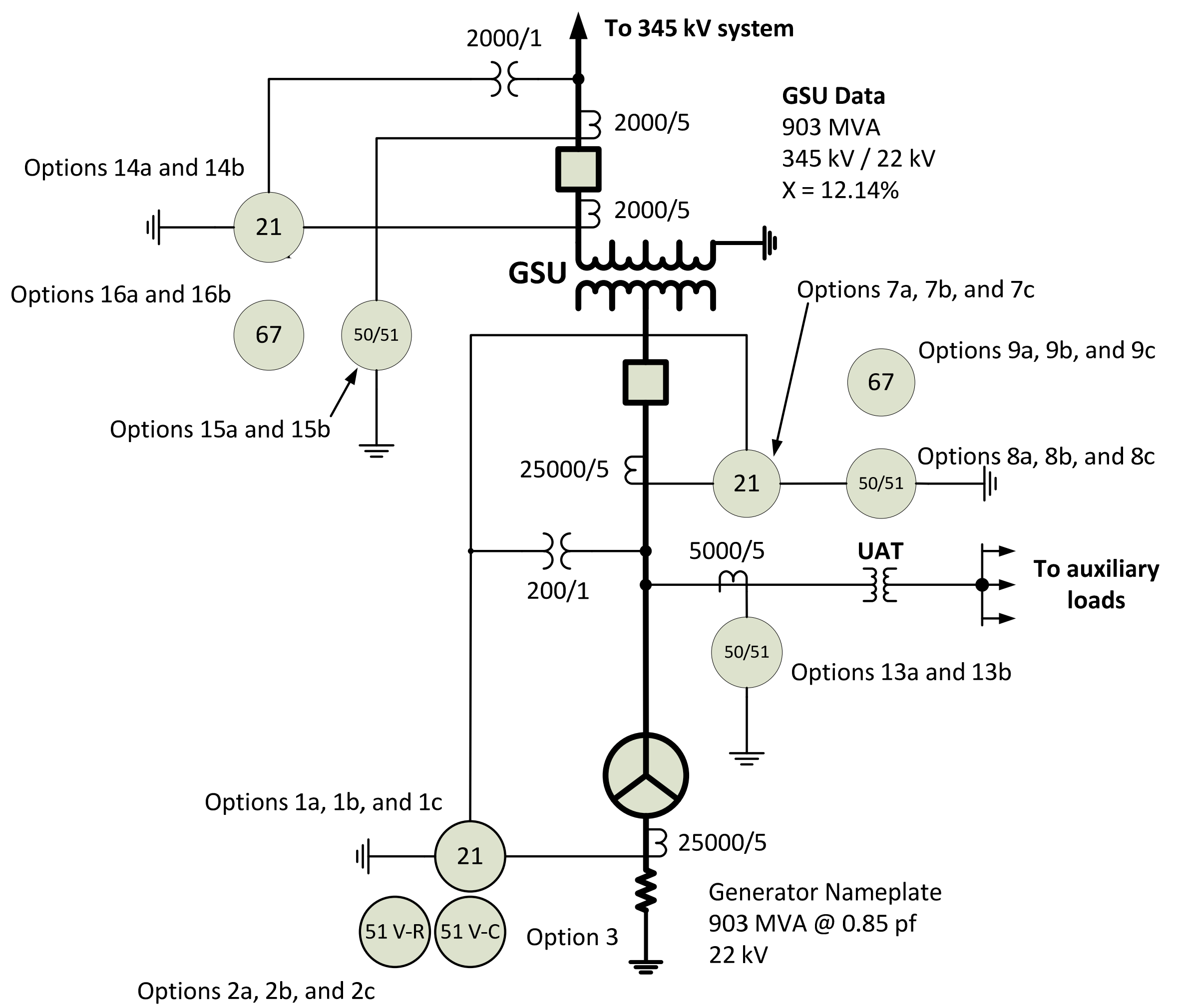


Figure 4. Relay Connection for corresponding synchronous options.

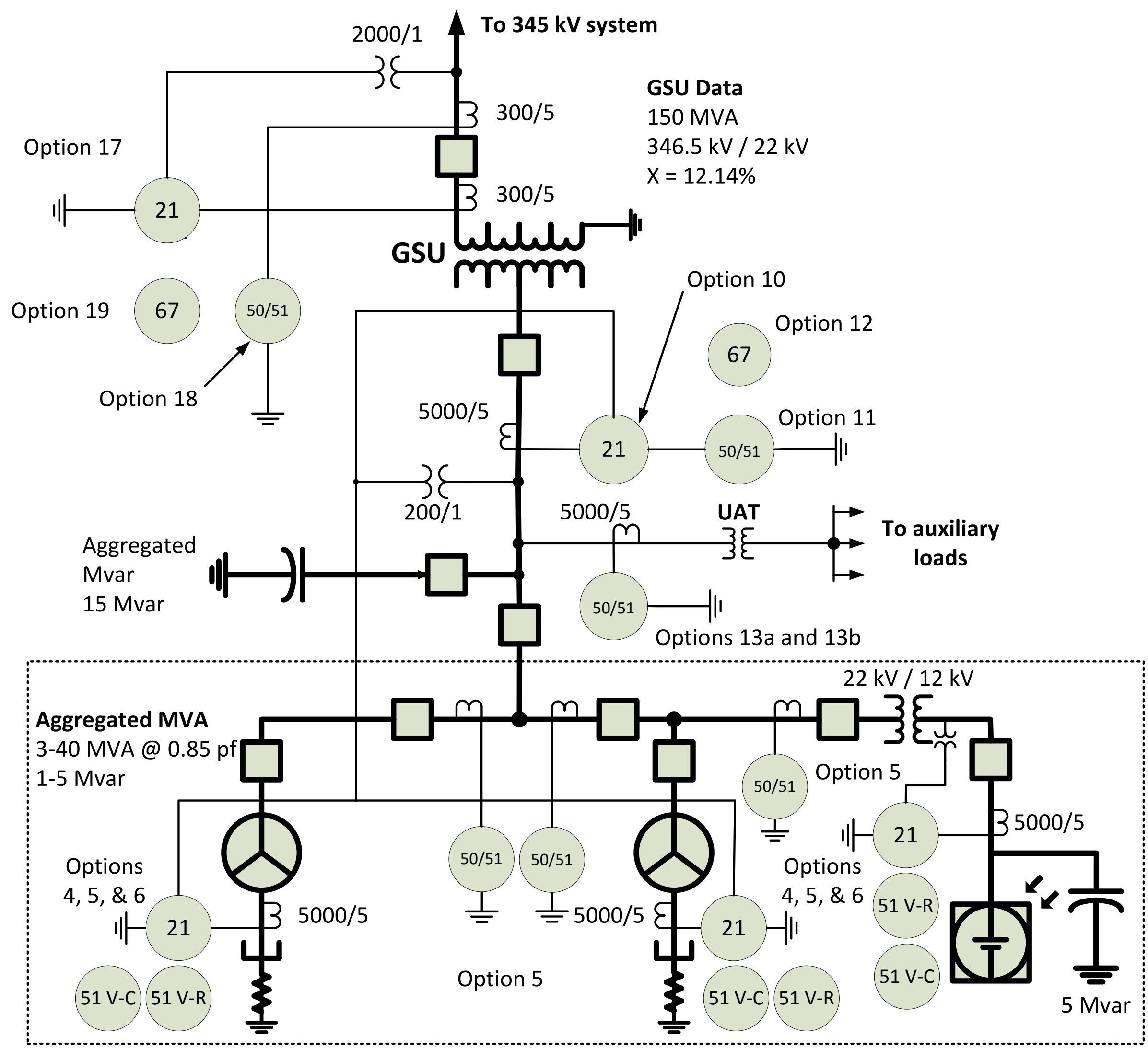


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which changes its sensitivity as a function of voltage (“voltage-restrained”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer’s turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer’s turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

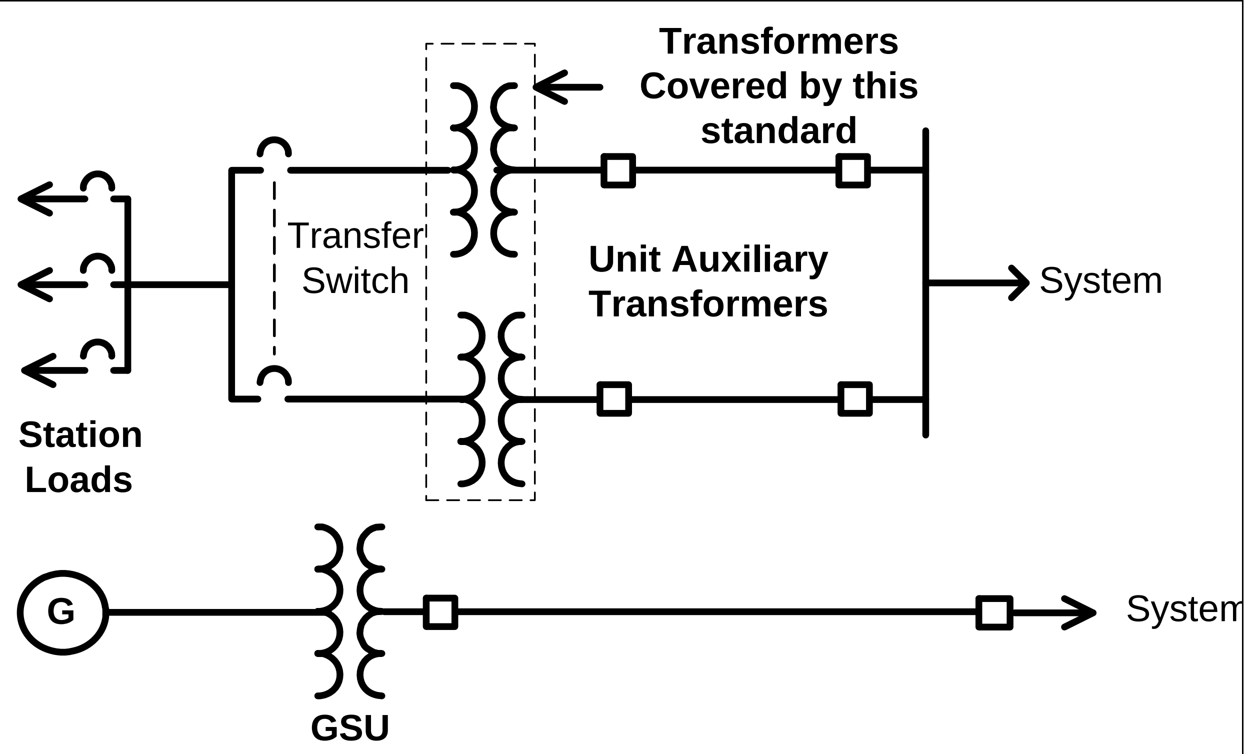


Figure-6 – Auxiliary Power System (independent from generator).

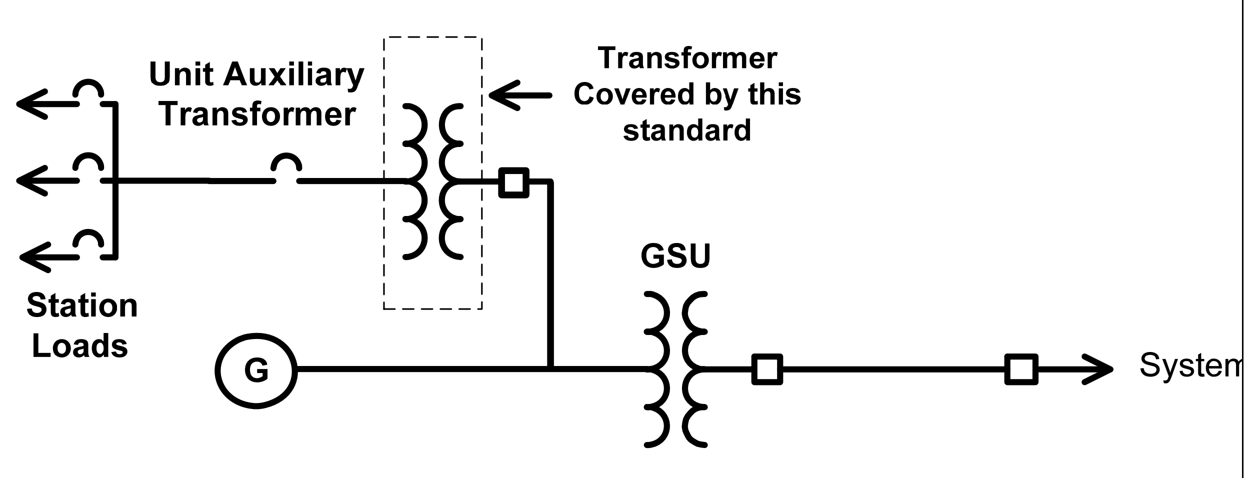


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.

These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations.	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8449 \pm 1.1546}{2}$$

$$\left|V_{low-side}\right| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = \left|V_{low-side}\right| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

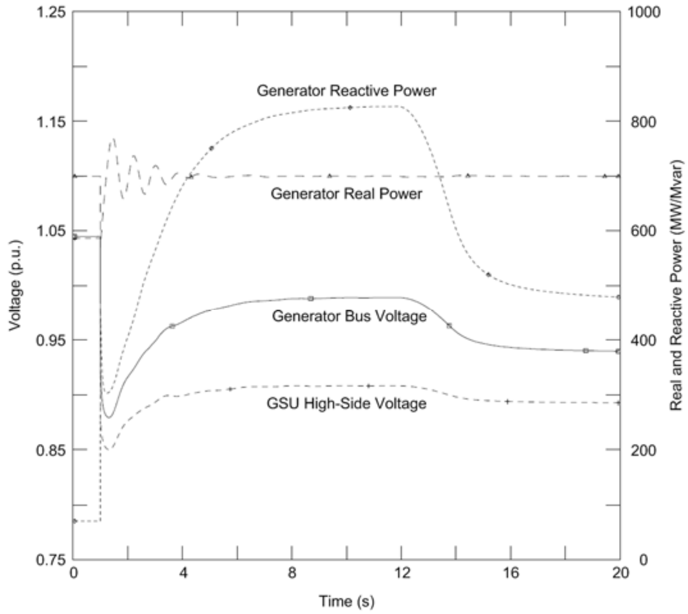
$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \dfrac{V_{bus\_simulated}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $Z_{sec} = Z_{pri} \times \dfrac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $$P = \ GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

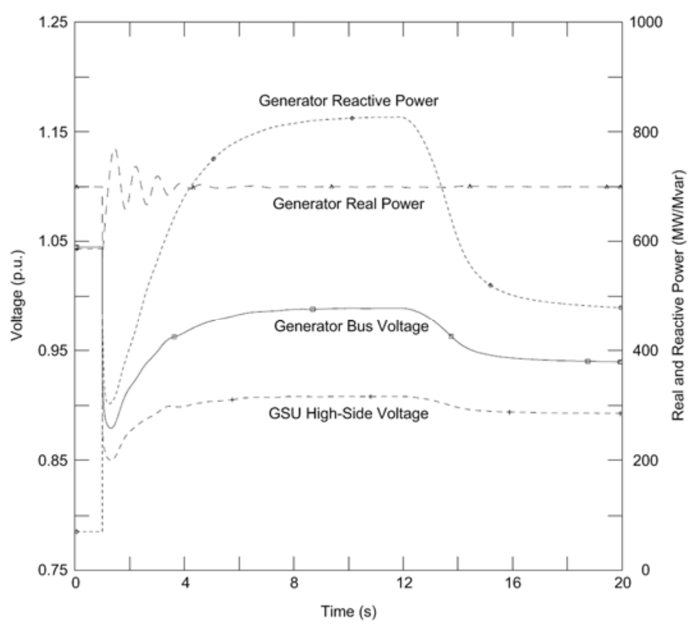
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle - 39.2°\ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2° \; MVA}{1.73 \times 21.9 \; kV}$$

$$I_{pri} = 3473\angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2° \; A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2° \; A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903 \; MVA \times 0.85$$

$$P_{Synch} = 767.6 \; MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \, \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \, \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0° \, \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u.\times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

Example Calculations: Options 8a and 9a

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 8b and 9b

Apparent power (S):

Eq. (106) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

Example Calculations: Options 8a, 9a, 11, and 12

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1\ \angle -39.2°\ MVA}{1.73\ \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061\ \angle -58.7°\ A}{\frac{25000}{5}} + \frac{4755\angle -39.2°\ A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle -56.8°\ A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle -56.8°\ A \times 1.00$$

$$I_{\sec limit} > 9.514\angle -56.8°\ A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding

Example Calculations: Options 8c and 9c

generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

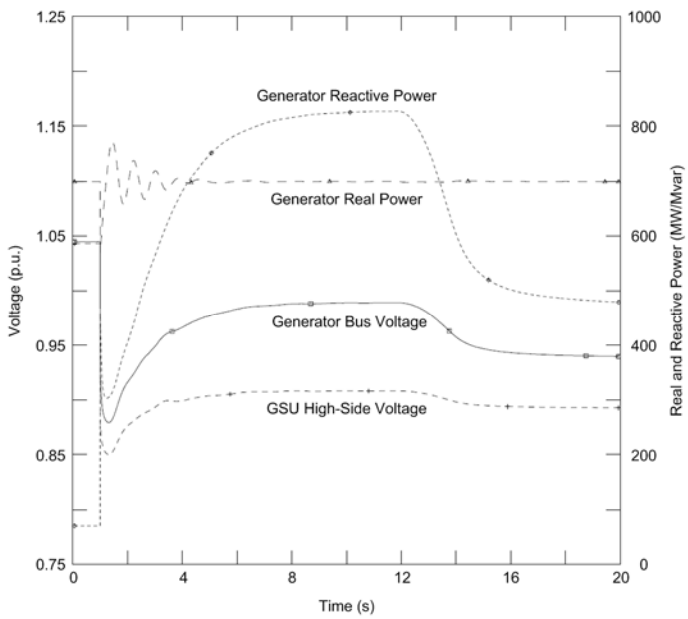
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (122) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Example Calculations: Options 8c and 9c

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

Example Calculations: Option10

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2^\circ\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2^\circ\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2^\circ\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

Example Calculations: Option10

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < \ 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 11 and 12

Real Power output (P):

Eq. (134) $P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

Example Calculations: Options 13a and 13b

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \mathrm{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $I_{\sec limit} > I_{sec} \times 150\%$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u. \times V_{nom}$

Example Calculations: Option 14a

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

Example Calculations: Option 14a

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

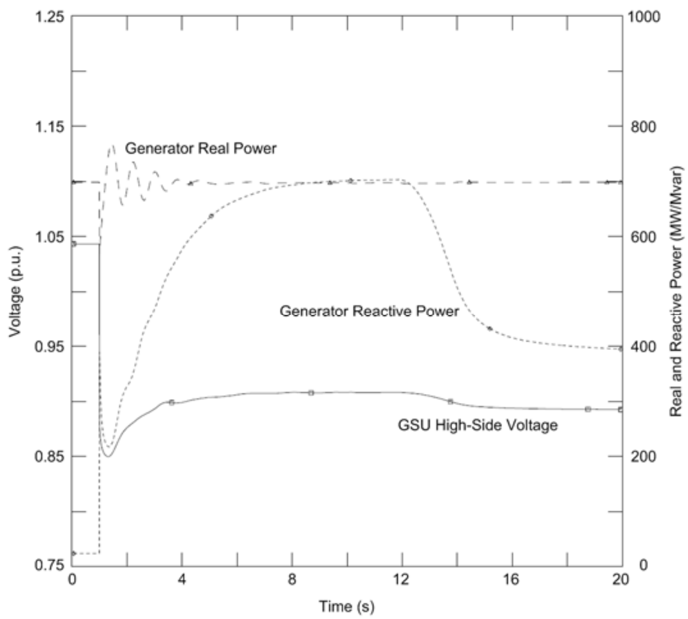
$$Q = 703.6\ Mvar$$

$$V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (152) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line. Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle -52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

Example Calculations: Options 15a and 16a

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85\ p.u.\times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

Example Calculations: Options 15a and 16a

$$I_{sec} = \frac{2280.6\angle -52.8°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\,A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\,A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\,A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line. Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b

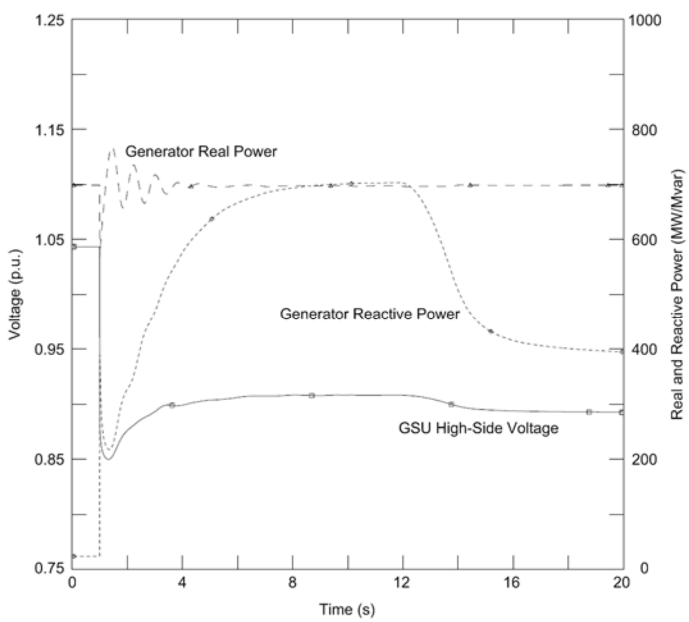
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (171) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

Example Calculations: Options 15b and 16b

$$I_{pri} = 1831.2\angle -45.1°\,A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\,A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 4.578\angle -45.1°\,A \times 1.15$$

$$I_{\sec limit} > 5.265\angle -45.1°\,A$$

Example Calculations: Option 17

Option 17 represents the calculation for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (175) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\,MVA \times 0.85$$

$$P_{Asynch} = 102.0\,MW$$

Reactive Power output (Q):

Eq. (176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

Example Calculations: Option 17

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (183) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $V_{nom} = 1.0\ p.u. \times V_{nom}$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Example Calculations: Options 18 and 19

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\mathrm{sec}\,limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-~~1~~2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~ **Background:**

6. After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

~~**7.1. Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8. Compliance Monitoring Process

8.1. 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.

8.2. 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 Compliance Enforcement Authority (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 Generator Owner, Transmission Owner, and Distribution Provider 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None

~~Table of Compliance Elements~~

.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

~~E. Interpretations~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	

~~PRC-025-1~~2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads~~.),~~), the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~ [5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 15~~ [6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~ [7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 17[8]~~	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 18[9]~~	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 19~~[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				

[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~. —~~) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~—~~installed on the high-side of the GSU transformer	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		~~OR~~		
	~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 7~~line[11]	~~14b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~	~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~
	~~The same application continues on the next page with a different relay type~~			

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[4]	**~~Pickup~~ Setting Criteria**
~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators~~	~~Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	~~15a~~	~~0.85 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor~~
		OR		
		~~15b~~14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The ~~overcurrent~~impedance element shall be set ~~greater~~less than ~~115% of~~ the calculated ~~current~~impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit	Phase ~~directional~~instantaneous overcurrent supervisory element (~~67~~e.g., 50) – associated with current-based, communication-	~~16a~~15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
or generating plant~~.~~ (Elements may also supply generating plant ~~load.~~ loads) – connected to synchronous generators	assisted schemes where the scheme is capable of tripping for loss of communications ~~directional toward the Transmission system~~ installed on the high-side of the GSU transformer and remote end of the line and/or phase ~~directional~~ time overcurrent relay (~~67) – directional toward the Transmission system~~e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~and remote end of the line[12]	15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 10~~line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator-side of~~ and on the ~~GSU transformer use Option 11~~remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator-side of~~ and on the ~~GSU transformer use Option 12~~remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

16 If the relay is installed on the generator-side of the GSU transformer use Option 12.

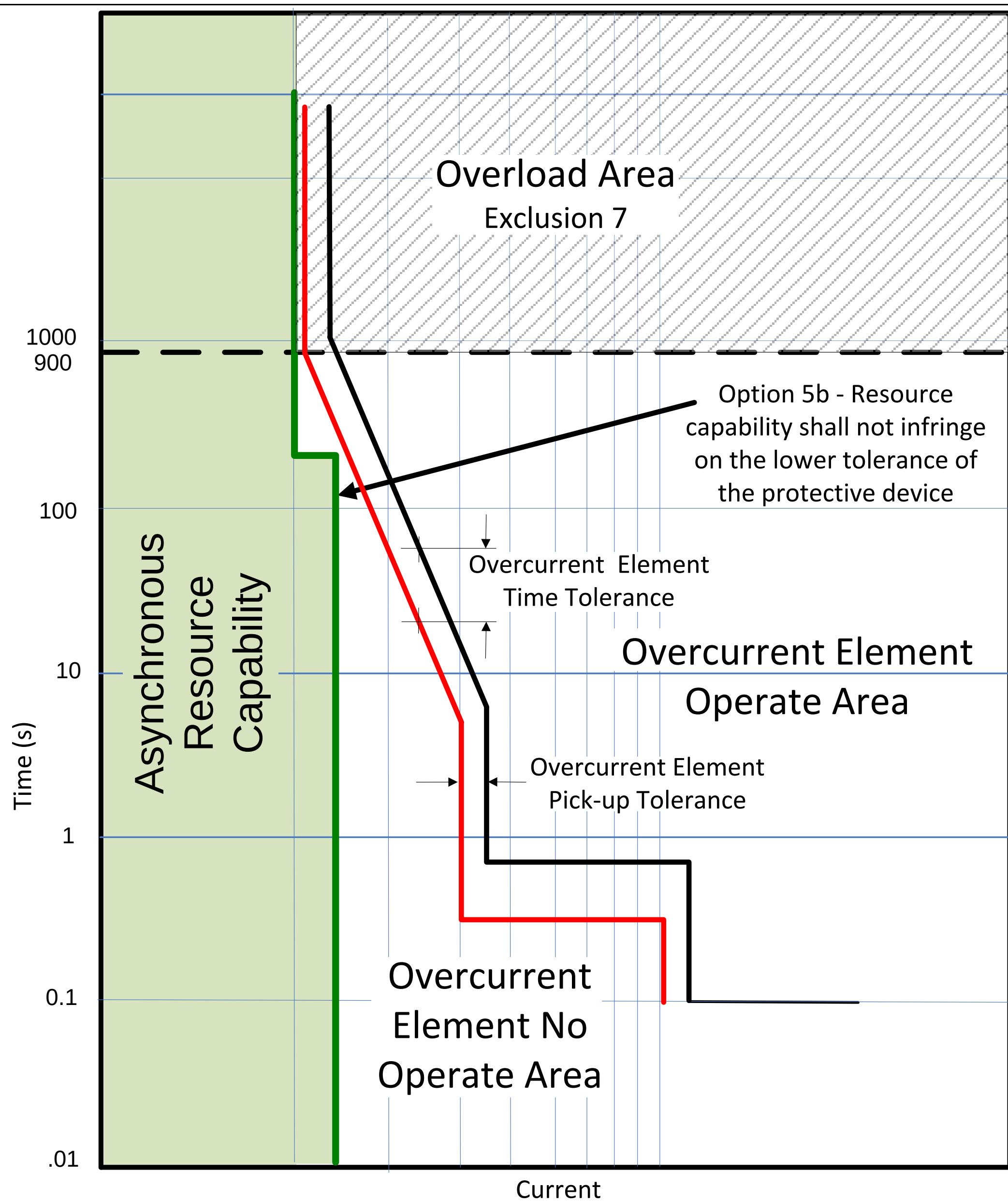


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard

[17] ~~http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf~~ http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

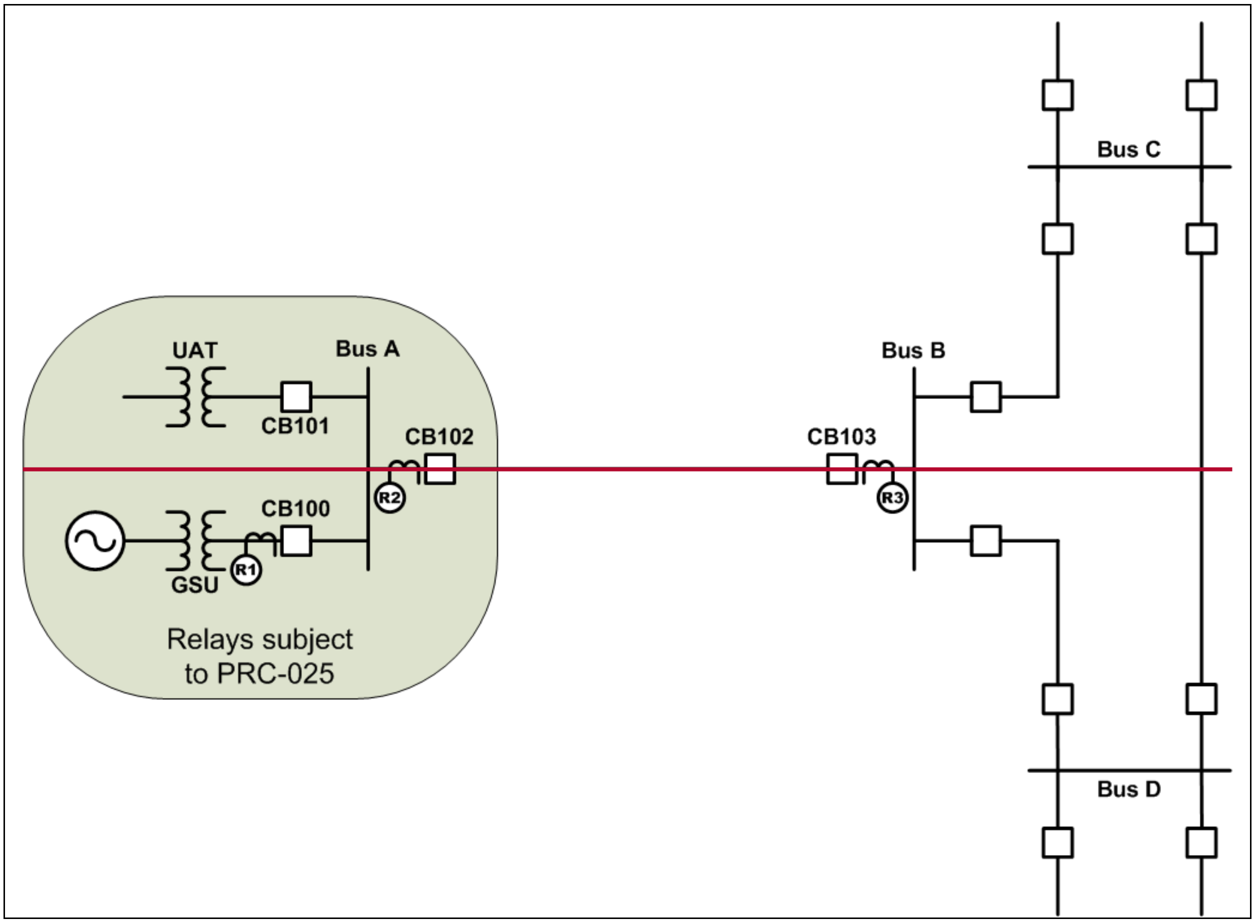
Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

~~In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


Bus C
UAT
Bus A
Bus B
CB101
CB102
CB103
CB100
R2
R3
R1
GSU
Relays subject
to PRC-025
Bus D

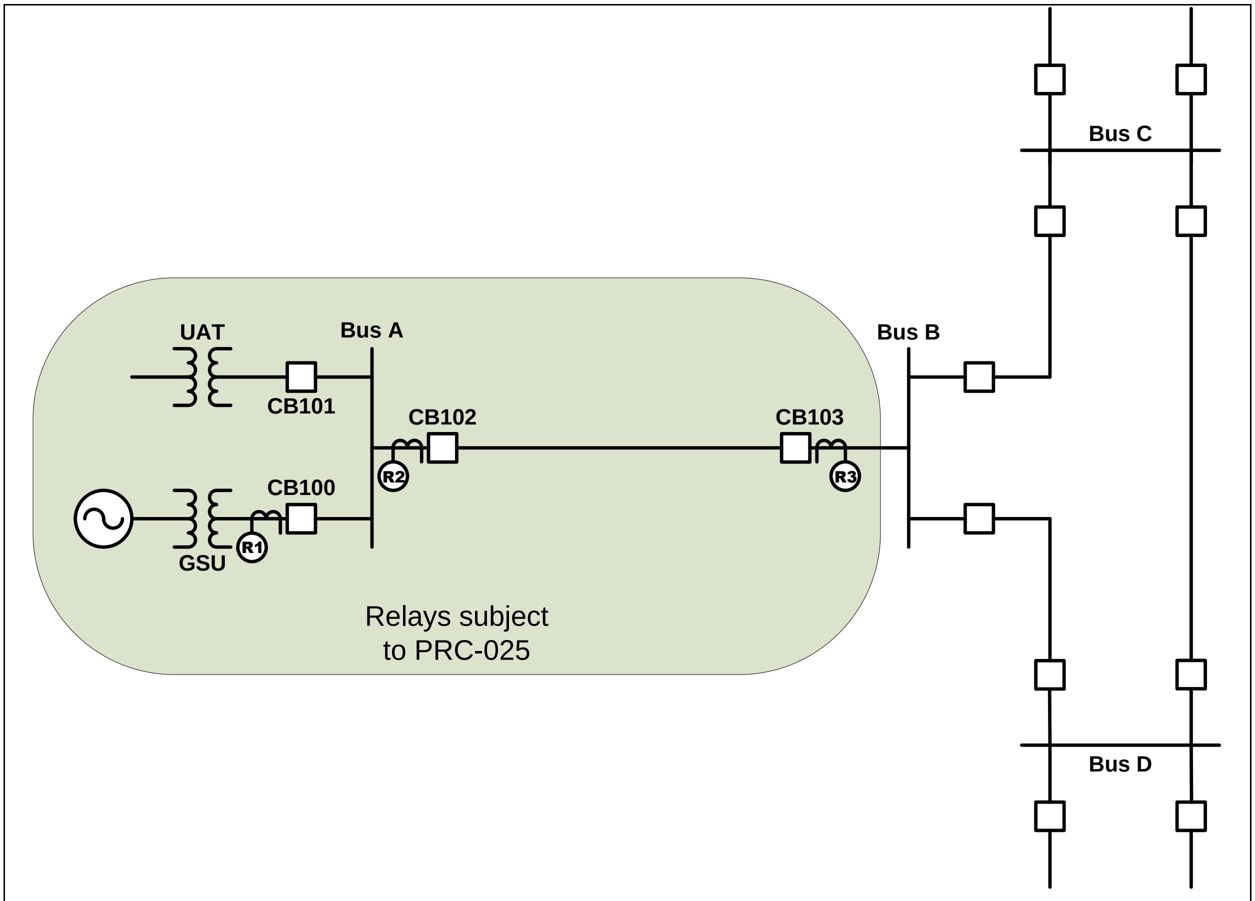


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

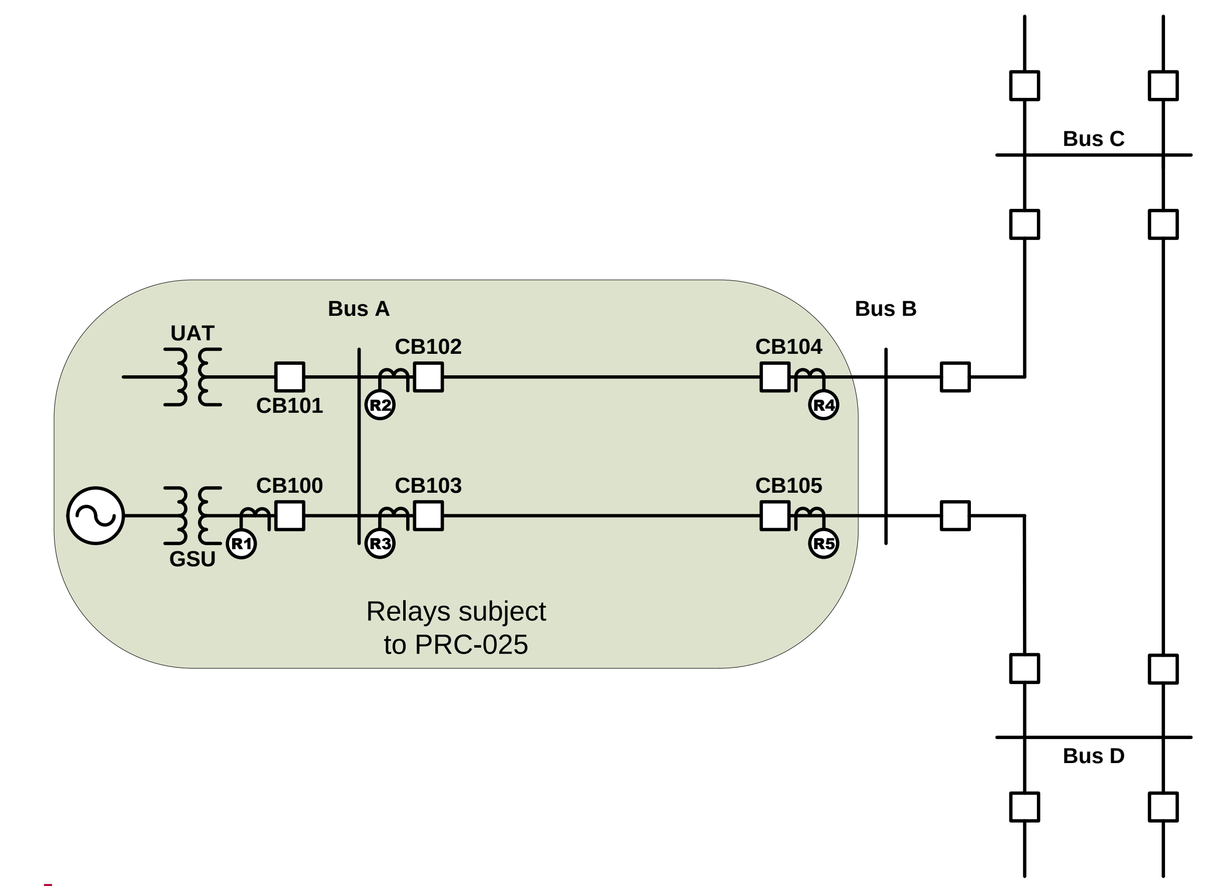


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

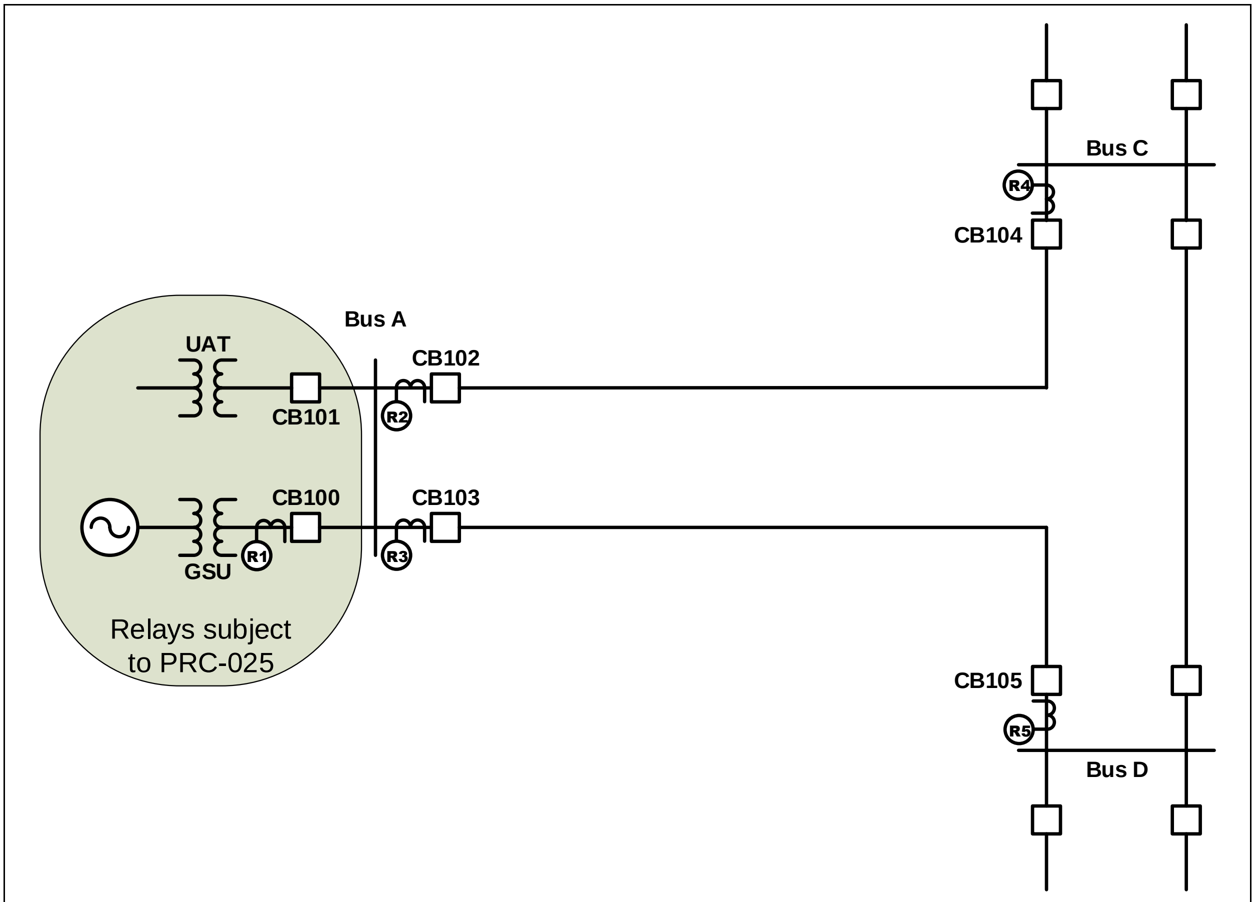


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-~~-~~-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault **that is not cleared by the transmission line breakers.** In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and **normal loading conditions.** However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to*

> *clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. ~~See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.~~

~~Phase Time Overcurrent Relay – Voltage Controlled (51V-C)~~

~~Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the~~See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

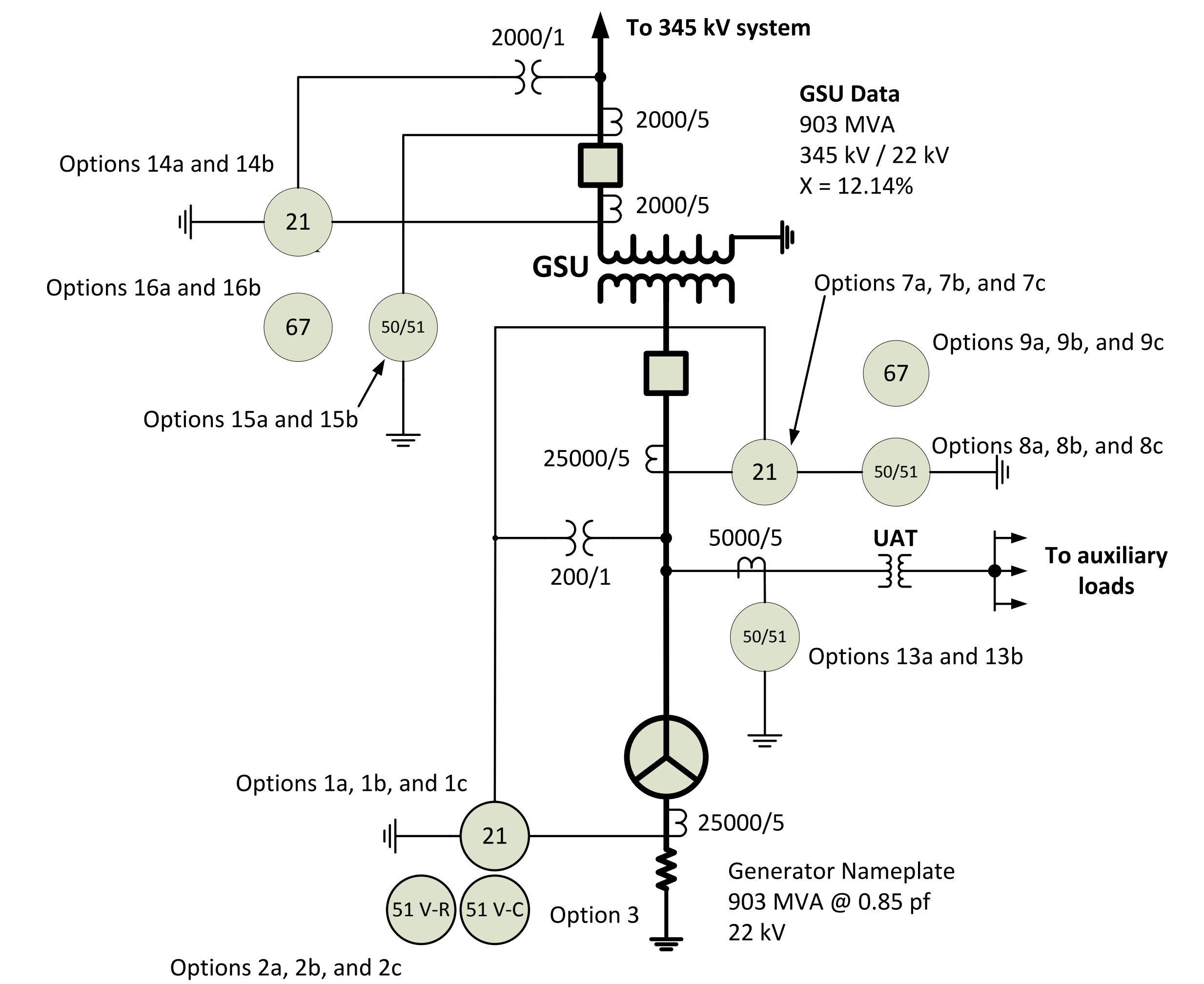


Figure 4. Relay Connection for corresponding synchronous options.

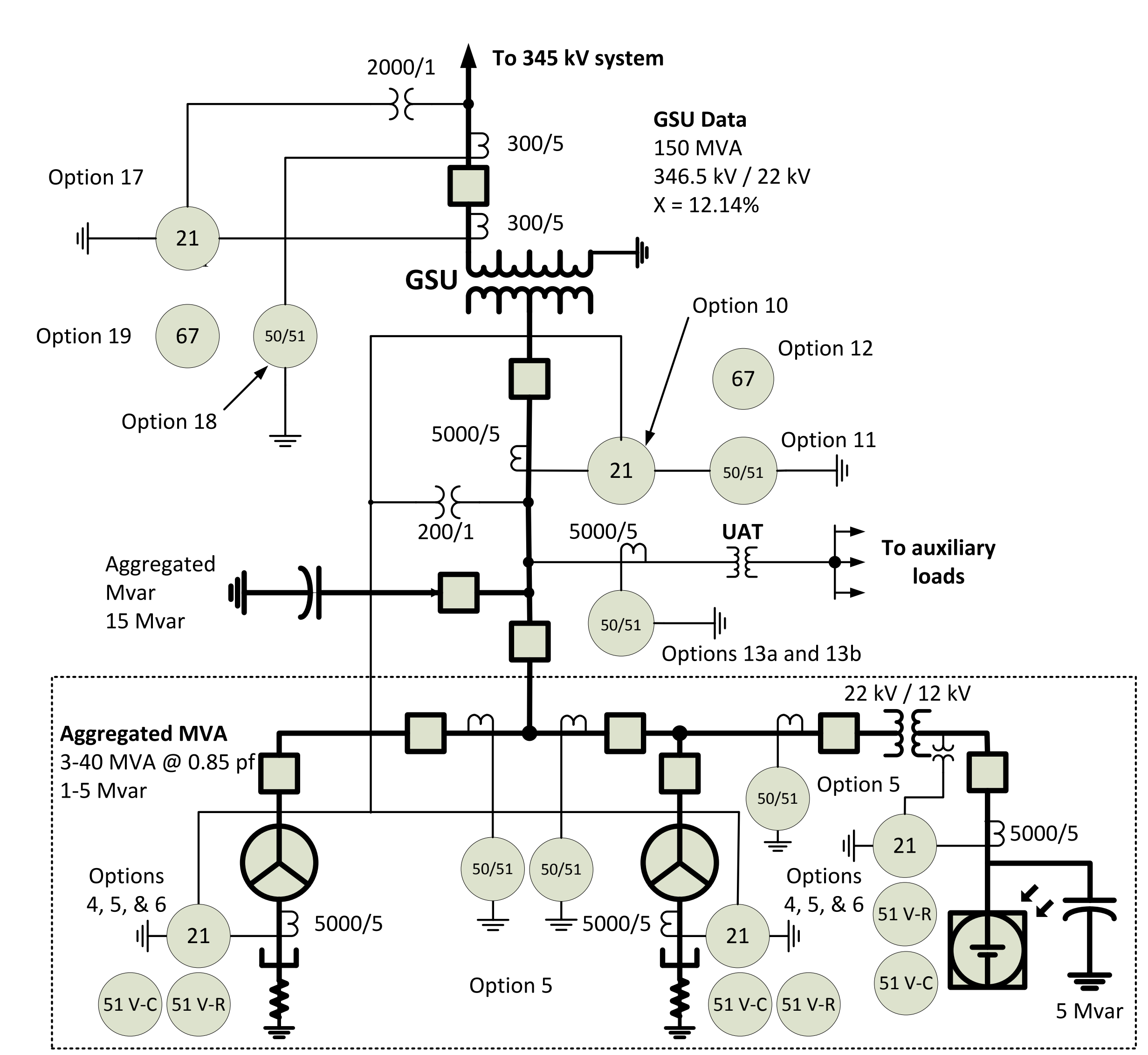


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times,~~ by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~ in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage-~~-~~Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage- Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b)

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying~~of phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer~~ and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~overcurrent~~impedance element ~~overall~~than Options 7a or 7b.

For Options 7a and 7b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 7c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.~~

~~Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.~~

~~Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.~~

~~Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~

~~For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW~~

~~capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~

~~For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.~~

~~Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.~~ Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more

~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.
~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

~~Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

~~Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19. Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~
~~Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~
~~For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard.

Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

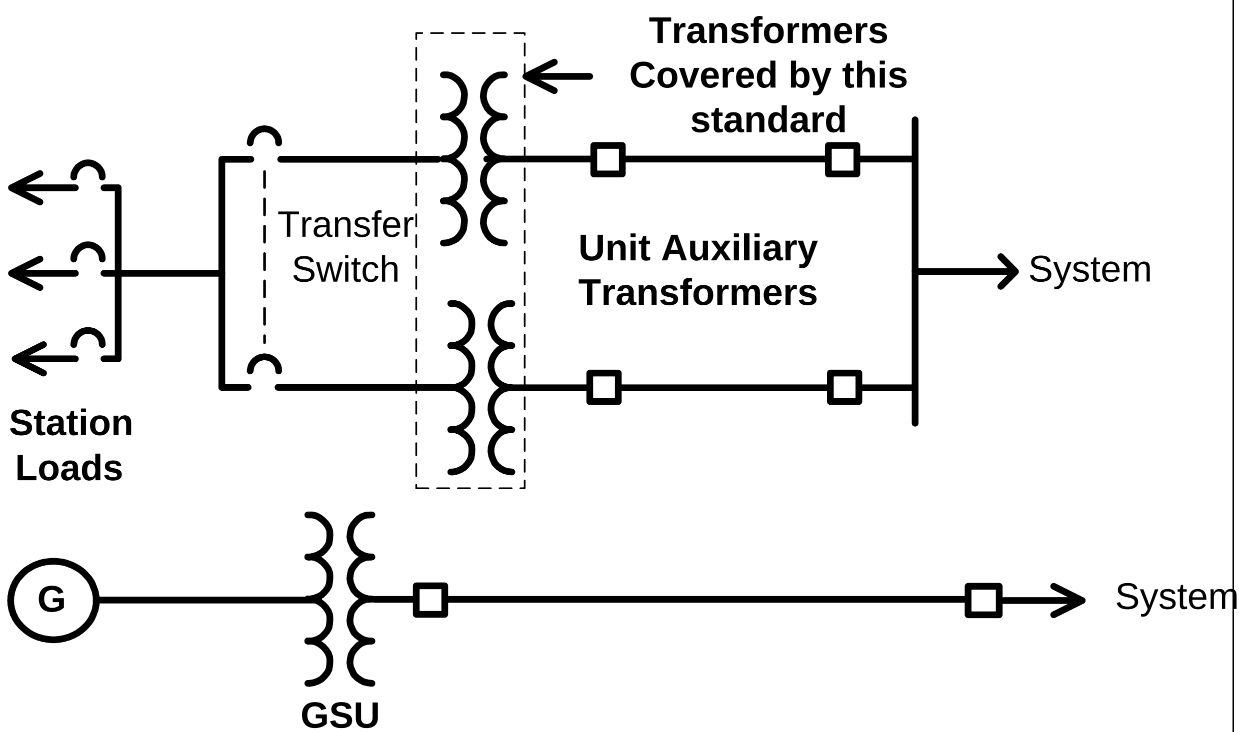


Figure-6 – Auxiliary Power System (independent from generator).

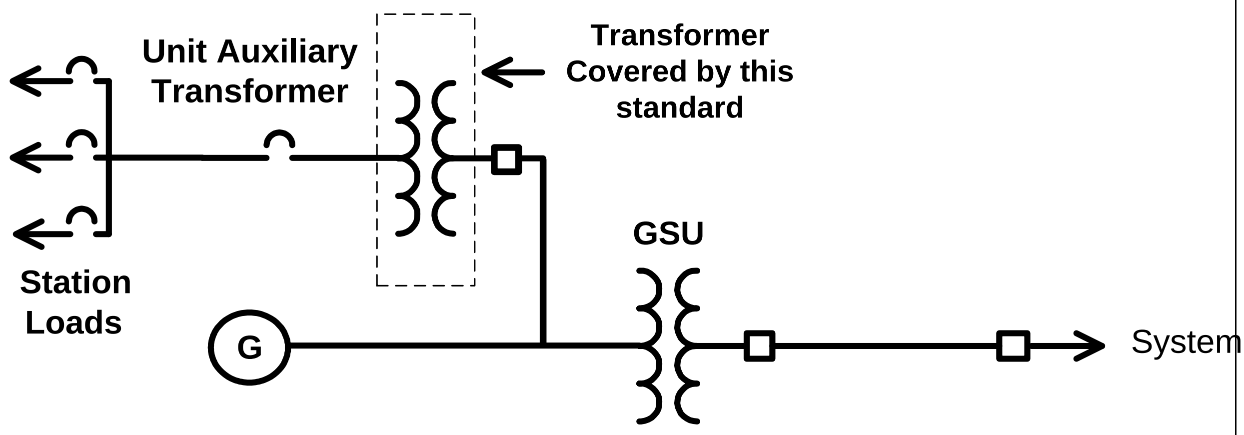


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$

Example Calculations.	
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\mathrm{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\mathrm{sec}\,limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\mathrm{sec}\,limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\mathrm{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle-58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}} \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

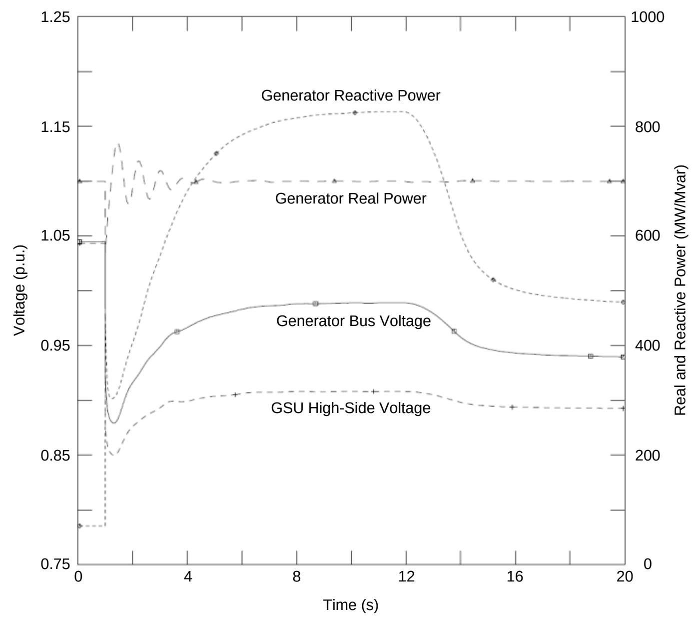
$$Q = 827.4\ Mvar$$

$$\cancel{V_{bus}} V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \cancel{\frac{V_{bus}^2}{S^*}} \frac{V_{bus\_simulated}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}}\ \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.~~

In this simulation the following values are derived:

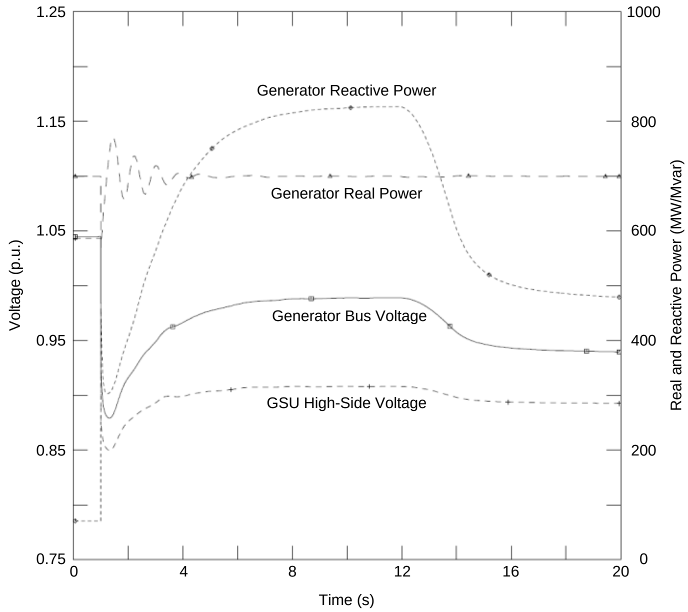
$$Q = 827.4\ Mvar$$

$$\cancel{V_{bus}} V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c



Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \cancel{\frac{S}{\sqrt{3} \times V_{bus}}}\frac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Option 2c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C)~~— voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21)~~—~~ directional toward the Transmission system.

Example Calculations: Option 4

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Example Calculations: Option 4

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option ~~5~~5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option ~~5~~5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2^{\circ}\ MVA$$

Primary current (I_{pri}):

Eq. (68) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{gen}}$

Example Calculations: Option ~~5~~5a

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option ~~5~~5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: ~~Options 7a and 10~~Option 5b

~~This~~Similarly to Option 5a, this example represents the calculation for ~~a mixture of~~three asynchronous ~~(i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations)~~generators applying a phase ~~distance~~overcurrent (e.g., 50, 51, or 51V-R) relay ~~(21) directional toward the Transmission system.~~. In this application it was assumed that 20 Mvar of total static compensation was added.

~~**Synchronous Generation (Option 7a)**~~

Real Power output (~~P_{sync}):~~P):

Eq. (71) $$\cancel{P_{synch} = GEN_{synch\_nameplate} \times pf} P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Example Calculations: ~~Options 7a and 10~~Option 5b

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

Example Calculations: ~~Options 7a and 10~~Option 5b

$$I_{sec} = 3.473\angle - 39.2° \, A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903 \, MVA \times 0.85$$

$$P_{Synch} = 767.6 \, MW$$

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6 \, MW$$

$$Q_{Synch} = 1151.3 \, MW$$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0 \, MW + j1151.3 \, Mvar$$

Example Calculations: Options 7a and 10

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

Example Calculations: Options 7a and 10

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~84 to satisfy the margin requirements in Options 7a and 10~~:~~.

Eq. (~~81~~87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

~~Example Calculations: Options 7a and 10~~

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~84~~90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a and 9a

Apparent power (S):

Eq. (~~86~~92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~87~~93) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (~~88~~94) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more ~~complex~~precise calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Example Calculations: Options 8b and 9b

Real Power output (P):

Eq. (~~90~~96) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~91~~97) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (~~93~~99) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (~~94~~100) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

Example Calculations: Options 8b and 9b

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101)

$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)

$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Example Calculations: Options 8b and 9b

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Example Calculations: Options 8b and 9b

Secondary current (I_{sec}):

Eq. (~~102~~108)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110)
$$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P~~$_{Asynch}$~~):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (~~112~~118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2° \; MVA}{1.73 \; \times 20.81 \; kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (~~114~~120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \; A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \; A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \; A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98.~~118.

Eq. (~~115~~121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \; A \times 1.00$$

$$I_{\sec limit} > 9.514 \angle -56.8° \; A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~ overcurrent relay~~.~~ (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter

Example Calculations: Options 8c and 9c

reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

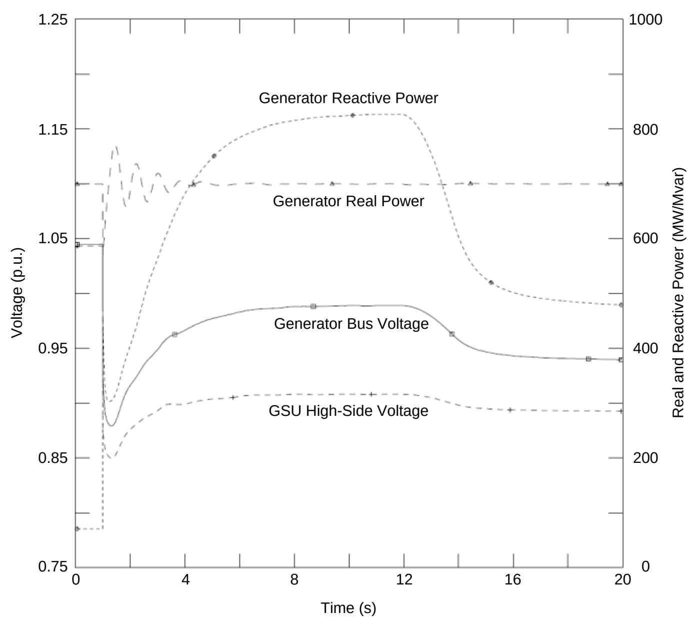
In this simulation the following values are derived:~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

$$Q = 827.4\ Mvar$$

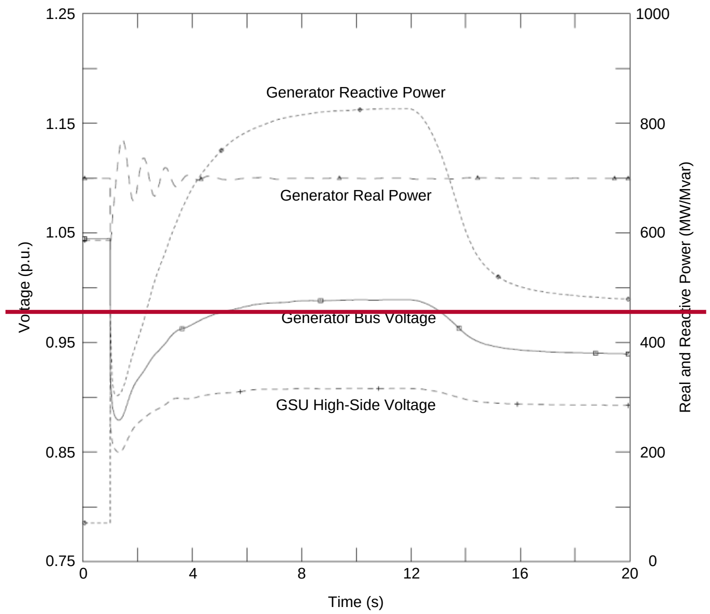
$$\cancel{V_{bus}}V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (~~116~~122) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (~~117~~123) $I_{pri} = \cancel{\frac{S}{\sqrt{3} \times V_{bus}}}\frac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (~~118~~124) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8c and 9c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (~~119~~125) $$I_{\sec\,limit} > I_{sec} \times 115\%$$

$$I_{\sec\,limit} > 5.758\ A \times 1.15$$

$$I_{\sec\,limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21)~~—~~ directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~120~~126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~121~~127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~122~~128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option10

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~123~~129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~124~~130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~125~~131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (~~126~~132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

Example Calculations: Option10

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~127~~133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~ overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~128~~134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~129~~135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~130~~136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~131~~137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~132~~138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~133~~139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

Example Calculations: Options 11 and 12

To satisfy the 130% margin in Options 11 and12:

Eq. (~~134~~140) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2° \ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (~~135~~141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \ MVA}{1.73 \times 13.8 \ kV}$$

$$I_{pri} = 2510.2 \ A$$

Secondary current (I_{sec}):

Eq. (~~136~~142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \ \mathrm{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (~~137~~143) $$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~138~~144) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~139~~145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high-side~~line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (~~140~~146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Example Calculations: Option 14a

Apparent power (S):

Eq. (~~141~~147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (~~142~~148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~143~~149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (~~144~~150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~145~~151)
$$Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} <\ 15.283\angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that~~connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

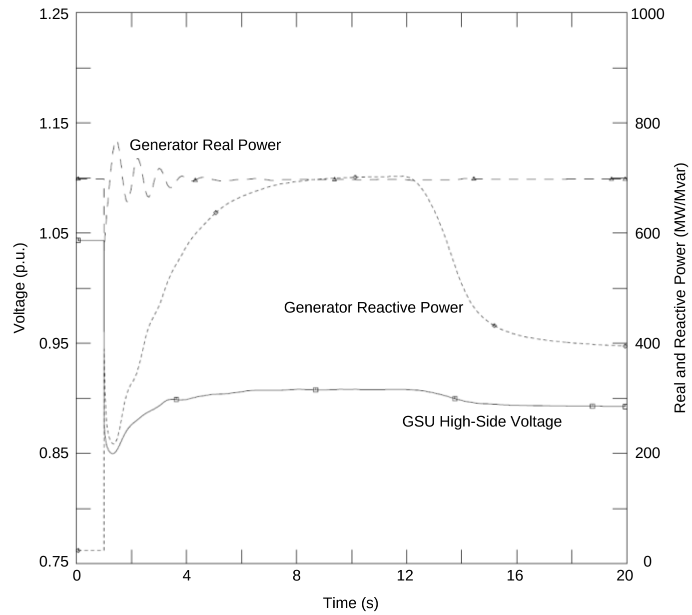
$$Q = 703.6\ Mvar$$

Example Calculations: Option 14b

$$\cancel{V_{bus}}V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~152) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (~~147~~153) $$Z_{pri} = \cancel{\frac{V_{bus}^2}{S^*}}\frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

Example Calculations: Option 14b

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~148~~154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (~~149~~155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\ \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~150~~156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\ \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~—~~installed on the high-side of the GSU transformer~~.~~ and remote end of the line. Option 16a represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~—~~directional toward the Transmission system~~–~~ installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~151~~157) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~152~~158) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Example Calculations: Options 15a and 16a

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high-side~~line nominal voltage:

Eq. (~~153~~159) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (~~154~~160) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (~~155~~161) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (~~156~~162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and ~~15b~~16a:

Eq. (~~157~~163) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

Example Calculations: Options 15a and 16a

$$I_{sec\,limit} > 5.701 \angle -52.8° \, A \times 1.15$$

$$I_{sec\,limit} > 6.56 \angle -52.8° \, A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \, MW$$

$$Q = 921.12 \, Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85 \, p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345 \, kV$$

$$V_{bus\_remote\_substation} = 293.25 \, kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \, MW + j921.12 \, Mvar$$

$$S = 1157 \angle 52.8° \, MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~—~~installed on the high-side of the GSU transformer~~.~~ and remote end of the line. Option 16b represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~—~~directional toward the Transmission system~~–~~ installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

~~This example uses Option 15b as a simulation example~~Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the ~~in the~~ high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

In this simulation the following values are derived:

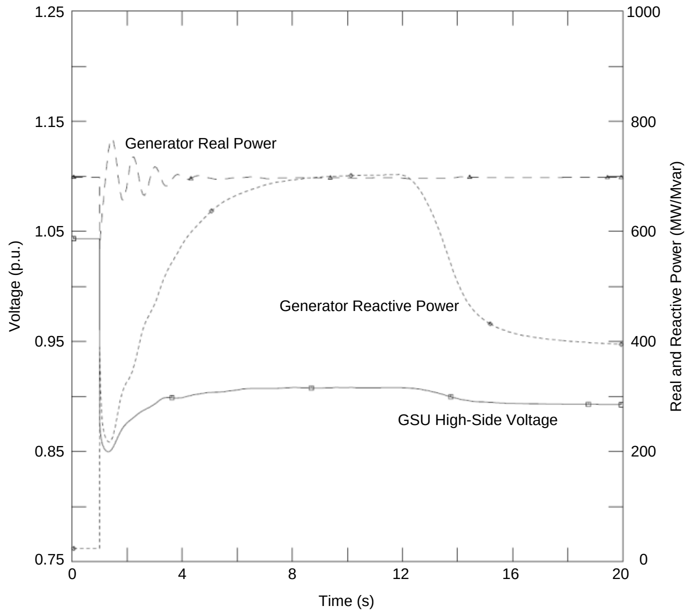
$$Q = 703.6\ Mvar$$

$$\cancel{V_{bus}}V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 15b and 16b



Apparent power (S):

Eq. (~~158~~171) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (~~159~~172) $$I_{pri} = \cancel{\frac{S^*}{\sqrt{3} \times V_{bus}}} \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (~~160~~173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\,A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (~~161~~174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 4.578\angle -45.1°\,A \times 1.15$$

$$I_{\sec limit} > 5.265\angle -45.1°\,A$$

Example Calculations: Option 17

Option 17 represents the calculation for ~~three asynchronous generation~~ Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21)~~–~~ directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~162~~175) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\,MVA \times 0.85$$

$$P_{Asynch} = 102.0\,MW$$

Reactive Power output (Q):

Eq. (~~163~~176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\,Mvar + 5\,Mvar + (3 \times 40\,MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\,Mvar$$

Example Calculations: Option 17

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high-side~~line nominal voltage for the bus voltage (V_{bus}):

Eq. (~~164~~177) $$V_{bus} = 1.0\ p.u.\times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (~~165~~178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~166~~179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181)
$$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, and then the maximum allowable impedance reach is:

Eq. (~~169~~182)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation~~relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~ that is~~. Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (~~170~~183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high-side~~line nominal voltage (V_{bus}):

Eq. (~~172~~185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (~~173~~186) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

Example Calculations: Options 18 and 19

$$I_{pri} = 220.5 \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189)
$$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale:

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

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1

Requested Approvals

- PRC-025-2 – Generator Relay Loadability

Requested Retirements

- PRC-025-1 – Generator Relay Loadability

Prerequisite Approvals

- None.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

- No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

The PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the version one enforcement dates. The first U.S. enforcement date of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. enforcement date of October 1, 2021 applies to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The proposed Option 5b reduces the implementation burden to the applicable entities.
- The proposed revisions to Options 14a, 14b, 15a, 15b, 16a, 16b, 17, 18, and 19 may give reason for entities to re-evaluate their settings for load-responsive protective relays.
- A few proposed Option(s) now include the 50 element.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 12 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 36 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

- PRC-025-1
  Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

- None.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

Unofficial Comment Form

Project 2016-04 Modifications to PRC-025-1

Do not use this form for submitting comments. Use the electronic form to submit comments on **Reliability Standard PRC-025-2 – Generator Relay Loadability**. The electronic form must be submitted by **8 p.m. Eastern, Thursday, September 7, 2017.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at 404-446-9689.

Background Information

Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, issues have been identified for specific Facility applications and load-responsive protective relays.

The revised PRC-025-2 standards addresses the concerns raised during implementation. In summary, those concerns include:

1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed power producing resources.
2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard.
3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s).
4. Prevent a lowering of dependability of protective relays directional toward the Transmission system at generating facilities that are remote to the transmission network.
5. Modify or eliminate the use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to “not trip” based on the criteria in Table 1.
6. Miscellaneous considerations for clarifications to the standard, Attachment 1, and/or Application Guidelines.

Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

   ☐ Yes
   ☐ No
   Comments:

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instanteous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

   ☐ Yes
   ☐ No
   Comments:

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

   ☐ Yes
   ☐ No
   Comments:

4. Do you agree that the proposed revisions in Table 1 for Options 14 thorugh 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

   ☐ Yes
   ☐ No
   Comments:

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

   ☐ Yes
   ☐ No
   Comments:

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

   ☐ Yes
   ☐ No
   Comments:

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement **is not** necessary, and (2) 36 months where equipment removal or replacement **is** necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

   ☐ Yes
   ☐ No
   Comments:

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

   ☐ Yes
   ☐ No
   Comments:

9. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

   ☐ Yes
   ☐ No
   Comments:

10. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If **yes**, please identify the conflict here.

    ☐ Yes
    ☐ No
    Comments:

11. Are you aware of a need for a regional variance or business practice that should be considered with this project? If **yes**, please identify the need here.

    ☐ Yes
    ☐ No
    Comments:

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

    Comments:

Violation Risk Factor and Violation Severity Level Justifications

PRC-025-2 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability. Note that no Requirement, Measure, or VRF/VSL changes have been made in this proposed PRC-025-2 Reliability Standard.

Each primary requirement is assigned a VRF and a set of one or more VSLs. 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 Reliability Coordination Standard Drafting Team (SDT) 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. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

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:[2]

- 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

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- 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 the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting 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 and VSL Justifications

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-2, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.
VSL Justifications – PRC-025-2, R1				
NERC VSL Guidelines				The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance				The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.

Proposed VSLs for PRC-025-2, R1	
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	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent 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 addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2016-04 Modifications to PRC-025-1

Reminder: Initial Ballot and Non-binding Poll Open through September 7, 2017

Now Available

An initial ballot for **PRC-025-2 – Generator Relay Loadability** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, September 7, 2017**

Balloting

Members of the ballot pools associated with this project may log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience any difficulties in navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project Project 2016-04 Modifications to PRC-025-1

Formal Comment Period Open through September 7, 2017
Ballot Pools Forming through August 23, 2017

Now Available

A 45-day formal comment period for **PRC-025-2 – Generator Relay Loadability**, is open through **8 p.m. Eastern, Thursday, September 7, 2017**.

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, August 23, 2017.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An initial ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 29 – September 7, 2017.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project Project 2016-04 Modifications to PRC-025-1

Formal Comment Period Open through September 7, 2017
Ballot Pools Forming through August 23, 2017

Now Available

A 45-day formal comment period for **PRC-025-2 – Generator Relay Loadability**, is open through **8 p.m. Eastern, Thursday, September 7, 2017**.

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Join the Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, August 23, 2017.** Registered Ballot Body members may join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every* ***6 months*** *and must be reset.*
- *The SBS* ***is not*** *supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

An initial ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted August 29 – September 7, 2017.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/101)
Ballot Name: 2016-04 Modifications to PRC-025-1 PRC-025-2 IN 1 ST
Voting Start Date: 8/29/2017 12:01:00 AM
Voting End Date: 9/8/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 251
Total Ballot Pool: 312
Quorum: 80.45
Weighted Segment Value: 80.99

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	50	0.806	12	0.194	0	7	12
Segment: 2	4	0	0	0	0	0	0	2	2
Segment: 3	73	1	44	0.759	14	0.241	0	4	11
Segment: 4	17	1	9	0.75	3	0.25	0	1	4
Segment: 5	74	1	39	0.75	13	0.25	0	5	17
Segment: 6	50	1	27	0.794	7	0.206	0	3	13
Segment: 7	2	0	0	0	0	0	0	0	2
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.6	6	0.6	0	0	0	1	0
Totals:	312	6	179	4.859	49	1.141	0	23	61

BALLOT POOL MEMBERS

Show All ▼ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Lauren Price		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Gary Nolan	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Memphis Light, Gas and Water Division	Allan Long		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Ohio Valley Electric Corporation	Scott Cunningham		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Chad Bowman		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Westar Energy	Kevin Giles		None	N/A
1	Western Area Power Administration	sean erickson		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	AEP	Aaron Austin		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		None	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City of Leesburg	Chris Adkins		Negative	Third-Party Comments
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons		Negative	Third-Party Comments
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Rutherford EMC	Tom Haire		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Anthony Solic		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
5	Arkansas Electric Cooperative Corporation	Moses Harris		None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy	Jamie Prater		None	N/A
5	Exelon	Ruth Miller		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Normande Bouffard		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jim Flucke	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Negative	Comments Submitted
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 312 of 312 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2016-04 Modifications to PRC-025-1 PRC-025-2 IN 1 NB
Voting Start Date: 8/29/2017 12:01:00 AM
Voting End Date: 9/8/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 234
Total Ballot Pool: 297
Quorum: 78.79
Weighted Segment Value: 85

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	42	0.894	5	0.106	19	11
Segment: 2	4	0	0	0	0	0	2	2
Segment: 3	69	1	40	0.816	9	0.184	10	10
Segment: 4	17	1	8	0.727	3	0.273	2	4
Segment: 5	70	1	32	0.821	7	0.179	11	20
Segment: 6	47	1	22	0.88	3	0.12	8	14
Segment: 7	2	0	0	0	0	0	0	2
Segment: 8	3	0.3	3	0.3	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	2	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Totals:	297	5.9	153	5.038	27	0.862	54	63

BALLOT POOL MEMBERS

Show All ▼ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Lauren Price		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos	Gary Nolan	Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		None	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Doug Hils		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Memphis Light, Gas and Water Division	Allan Long		None	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Chad Bowman		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Abstain	N/A
1	Tennessee Valley Authority	Howell Scott		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Negative	Comments Submitted
1	Westar Energy	Kevin Giles		None	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	AEP	Aaron Austin		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins		Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons		Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		None	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		None	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Rutherford EMC	Tom Haire		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	R. Scott Moore		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Abstain	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Anthony Solic		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Michael Ward		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		None	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeff Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Affirmative	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy	Jamie Prater		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Exelon	Ruth Miller		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder		None	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		None	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Abstain	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted
5	Omaha Public Power District	Mahmood Safi		Negative	Comments Submitted
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Affirmative	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Chris Mattson		Abstain	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Dan Ewing		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jim Flucke	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Abstain	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Abstain	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		None	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	David Greene		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 297 of 297 entries

Previous 1 Next

Comment Report

Project Name:	2016-04 Modifications to PRC-025-1 | PRC-025-2
Comment Period Start Date:	7/25/2017
Comment Period End Date:	9/8/2017
Associated Ballots:	2016-04 Modifications to PRC-025-1 PRC-025-2 IN 1 ST

There were 43 sets of responses, including comments from approximately 127 different people from approximately 96 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instantaneous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

4. Do you agree that the proposed revisions in Table 1 for Options 14 through 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement is not necessary, and (2) 36 months where equipment removal or replacement is necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

9. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

10. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict here.

11. Are you aware of a need for a regional variance or business practice that should be considered with this project? If yes, please identify the need here.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural	1	RF

						Electric Cooperative, Inc.		
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Ryan Strom	Buckeye Power, Inc.	4	RF
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF

					Karie Barczak	DTE Energy - DTE Electric	3	RF
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Con-Edison	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

Wayne Sipperly	New York Power Authority	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Greg Campoli	NYISO	2	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC

					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	City of Independence,	5	SPP RE

						Power and Light Department		
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
More clarity is needed on the implementation of Option 5b. "Resource capability" should be defined such that this value can be clearly determined. A detailed example for Option 5b which uses a plot similar to Figure A that discusses "documented tolerances" would be helpful.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The overcurrent element setting of 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor is appropriate in most cases. Texas RE recommends keeping the 130% threshold for overcurrent elements and allow for exceptions in those cases where entities are limited by manufacturer requirements or physical limitations.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solar facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.	
Likes 1	Jeffrey Watkins, N/A, Watkins Jeffrey
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Option 5b is helpful and a clear improvement. In addition, Reclamation recommends that Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the generator will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement. Or, as approved in PRC-024-2, if Option 5 cannot be satisfied for older equipment, a statement such as, "Document the identification of regulatory or equipment limitations."	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solare facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
What is the need for option 5a with 5b being an option? Option 5b shows the correct way protective relays should be set and coordinated with equipement. If the protection can be set above the capability of the equipement output, what would be the reason to set the pickups at 130% above MVA unless you want a fault to cause more damage to the equipement being the clearing time could be delayed?	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group has a concern that Figure A (page 32 redline version) doesn't provide enough clarity on its purpose in reference to Option 5b. Additionally, we have a concern that the figure is missing the appropriate labeling methodology. We would ask the drafting team to provide more clarity in the Application Guideline Section of the Standard in reference to the figure's significance to Option 5b as well as including the appropriate labeling methodology.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

AEP recommends the SDT use the same frame of reference for both the Option 5a in Table 1 and Figure A. As currently written, Table 1 states “The overcurrent element shall not infringe upon…” while Figure A states “Option 5b – Resource capability shall not infringe on…”.	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG is of the opinion that there is a discrepancy between the Relay setting criteria description for option 5b in Table 1 and the description contain in the Figure A, which should be corrected. Instead of “Option 5b – Resource Capability shall not infringe on the lower tolerance of the protective device” we recommend Figure A should state the following “Option 5b – Protective device overcurrent element settings lower tolerance tripping characteristic shall not infringe on the Resource capability” Additional clarification is required regarding if asynchronous resource capability accounts for forcing & boosting effects on the steady state fault current (not the subtransient and transient).	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
As written, NERC Reliability Standard PRC-025-2 Generator Relay Loadability does not account for equipment limitations of the generator step-up transformer or generation lead line that would not allow an entity to set it’s protective relays to the level as specified within the standard. The SDT needs add additional option for these application that is similar to option 5B.	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Not applicable to BPA.	
Likes 0	
Dislikes 0	
Response	

Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instantaneous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to “elements” please add the word “PRC-025 relay” in front to clearly state that only “PRC-025 relays” are applicable, not control systems, not protective algorithms, and not fuses. If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but “pickup” was struck and Option 5 refers to overcurrent elements. Where the standard refers to “elements,” Reclamation recommends the drafting team insert the words “PRC-025 relay” to clearly state that only PRC-025 relays are applicable, not control systems, protective algorithms, or fuses. If the drafting team meant to include more protective elements than relays, Reclamation recommends that the standard clearly state the applicable protective elements. This standard is written to zero-defect and subject matter experts must clearly understand where it does and does not apply. Unless the standard allows some room for a small amount of error to be corrected, the compliance thresholds must be absolutely clear.	
Likes 0	

Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to “elements” please add the word “PRC-025 relay” in front to clearly state that only “PRC-025 relays” are applicable, not control systems, not protective algorithms, and not fuses.

If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

67 and 50 elements/relays should be out of scope due to the possibility of creating a protection sheme that may not pick up when it should. See comments from Exelon.

Likes 0	
Dislikes 0	

Response

Ruth Miller - Exelon - 5

Answer	No
Document Name	
Comment	

With respect to phase directional instantaneous overcurrent supervisory elements (67 or 50) – associated with current-based communication protection systems please consider the following

1. These relays will be affecting loading/generator loadability only if communication system fail and there is a disturbance on the grid. The Standard should not assume both events at the same time.

2. Calculations performed to calculate the settings for these type of relays show that the settings are very close to the 3-phase fault current contributed from the generator in cases where sub-transient reactance of the machine is at a high value. This will compromise the protection scheme because the changes proposed will make the protection scheme very insensitive. In case of a high resistance phase-to-ground fault, the protection scheme will not pick up the fault at the generator end. In some extreme cases, the fault detector relay (67 or 50), if set according to the current draft PRC-025 guidelines, may have to depend on the field forcing provided by the Automatic Voltage Regulator (AVR) before the fault current reaches the setpoint. This will induce unnecessary delays in the protective action and may cause more damage to the BES element.

3. Exelon proposes the following changes:

    i. These types of relays (67 or 50) should be deleted from the scope of this Standard for the reasons described above.

    ii. If there is an issue with communication protection systems such that the pilot protection scheme acts like a simple overcurrent relay, and that condition is alarmed, then it is reasonable to require an entity to correct this condition within a short period of time. Suggest the SDT add a requirement to correct such a condition within a certain timeframe. For example the condition shall be corrected within a calendar quarter and if not resolved then the setpoints of 67 or 50 should be raised to a certain value.

    iii. If SDT still wants to keep these relays within scope in spite of the reasoning/alternatives provided above, the the existing setting criteria the following should be added:
    "Minimum of the criteria 15a (or 15b) or 25% of the sub-transient current contribution from the generator using a pre-fault voltage of 1.0 and generator sub-transient unsaturated reactance and the main power transformer positive sequence reactance.

Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	

Unfortunately, the addition of "e.g." does not add clarity. The SDT needs to clearly state what protection function each option in Table 1 applies to.

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Fischette - Michael Fischette - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	Project 2016-04 PRC-025-2Final.docx
Comment	
No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85. Link: http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf Please state that Technical Guidance is for examples only, guidance isn't enforceable and cannot alter the scope of compliance. See attached document for diagrams.	
Likes 1	Jeffrey Watkins, N/A, Watkins Jeffrey
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Answer	No
Document Name	

Comment

Figure 3 of the Guidelines and Technical Basis section discusses the inclusion of collector system protective elements; however, the NERC defined term “Element” specifically excludes collector systems in accordance with the NERC bulk Electric System Definition Reference Document dated April 2014; see page 21 of 85. http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

Reclamation recommends that the Guidelines and Technical Basis document state that it is an example only and is not enforceable, or remove the discussion on collector system protection elements.

If the drafting team intended to include collector system protective elements for zero-defect compliance monitoring and change management, Reclamation recommends the standard be revised to clearly state “PRC-025 collector system” or “PRC-025 collector system relay elements” throughout the standard, including the Applicability Section.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	No
Document Name	

Comment

There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term “Element” which specifically excludes collector systems via NERC and industry agreement in 2014.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	Yes
Document Name	

Comment	
It is an improvement and adds additional clarity.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Do you agree that the proposed revisions in Table 1 for Options 14 through 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
While it is not typical for a generator to be rated higher than the line connecting the GSU to the transmission system, PSE has concerns with setting the relays for the line based on the generator ratings. Protective relays should be set according to the equipment that they are intended to protect (i.e. line relays should be set to protect the line, transformer relays should be set to protect the transformer, and generator relays should be set to protect the generator). Setting a line relay to protect a generator, particularly when the line might be rated lower than the generator could result in damage to the line, and could potentially result in reduced reliability.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
No because if you have multiple radial lines exporting the power from a generator, each line may not have the capability of carry the full power output of the generator. Engineers should have the ability to study individual installations and set the protection correctly for the equipment installed.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	

Entities that performed calculations per NERC guidance and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Tri-State would like clarification on the phrase "and on the remote end of the line" used in the Relay Type column of Option 14. Looking at the red-lined language under "Figure 1" of the guidelines section, our understanding is that relay R3 is applicable only if it is set with an element directional toward the transmission system or is non-directional. If relay R3 is set directed toward the generator, it is not applicable. If that is the case we recommend splitting up the language between the 2 scenarios and adding a figure to make it clear. As it is currently written, it isn't clear that only the 1st of those scenarios is displayed in Figure 1.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Entities that took NERC at their word in performing calculations and (where necessary) making changes under PRC-025-1 should be “grandfathered” for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	

While it is not typical for a generator to be rated higher than the line connecting the GSU to the transmission system, PSE has concerns with setting the relays for the line based on the generator ratings. Protective relays should be set according to the equipment that they are intended to protect (i.e. line relays should be set to protect the line, transformer relays should be set to protect the transformer, and generator relays should be set to protect the generator). Setting a line relay to protect a generator, particularly when the line might be rated lower than the generator could result in damage to the line, and could potentially result in reduced reliability.

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	

This sentence is confusing: “Simulated line voltage coincident with the highest Reactive Power

output achieved during field -forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field -forcing”

Consider changing to: “Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field -fo response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field -forcing”???

Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
The term "pickup" clearly indicates what part of the overcurrent device setting needs to meet the criteria. Perhaps this term can be retained for current operated devices.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
"Pickup" setting indicates the minimum operating value. Please retain the leading term "Pickup".	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The applicability section states that PRC-025 applies to relays. Removing "Pickup" suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in	

addition to removing “Pickup”. Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

If Pickup is not removed:

Reclamation recommends the SDT provide clarifying language describing what removing “Pickup” means. Pickup for PRC-025 refers to “PRC-025 Relays,” meaning actual relays at the individual generators with pickup settings. This does not include 1) any individual generator control systems, 2) collector system protective relays that may be installed on the padmount transformers, or 3) collector system protective relays on the radial collectors at the collector substation.

If Pickup is removed:

Reclamation recommends the SDT decide what protective relays are to be included and explicitly specify them. The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drafting team is looking for protective elements in addition to relays. If the SDT intends to include more than PRC-025 protective relays, the applicability criteria must be adjusted in addition to removing “Pickup.”

Reclamation recommends the PRC-025 Applicability section should specifically reference 1) individual generator control systems that may trip the individual power producing resource, 2) collector system protective relays that may be installed on the padmount transformers, or 3) collector system protective relays on the radial collectors at the collector substation.

Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	

The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing “Pickup”. Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

The setting that has to be met per the standard is the pickup setting, the standard does not talk about timing, just pickup, so why remove pickup from the table.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	Yes
Document Name	

Comment

It would provide added clarity to include “non-directional” in front of “phase instantaneous overcurrent supervising elements (e.g. 50)” and “phase time overcurrent relay (e.g. 51)”.

Likes 0	
Dislikes 0	

Response

Ruth Miller - Exelon - 5

Answer	Yes
Document Name	
Comment	
See comments provided in the response to Question 2 above.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the term “Overcurrent Element Pick-up Tolerance” still exists in Attachment 1 Figure A. Is this the SDT’s intention?	
Likes 0	
Dislikes 0	

Response

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
I do not agree with application of this standard. Protection should be set up and coordinated for individual installs not by generitc percentages above MVA nameplates. Setting criteria should not be enforced by NERC unless NERC is willing to take responsibility for any equipment damage from settings being set to high.	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement is not necessary, and (2) 36 months where equipment removal or replacement is necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

The 36 months may not be long enough to replace the relays depending on the number of relays that have been identified for replacement. Suggest a change to 60 months, or "prorated" (The implementation period will be different based on the number of protection units that have been identified for replacement).

Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

This does not allow for time needed to make any changes based on the new revision. Altering the calculations and re-reviewing current changes that have been made in accordance with PRC-025-1 will take time. Any non-compliant relays found due to the new revision may cause a delay in our ability to comply. We would request that more time be given to allow for proper implemenation of this new revision.

Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

Depending on the date that version 2 would eventually be approved, it is possible that that the version 2 enforcement date, for those assets explicitly in scope under version 1, could actually be earlier than the existing version 1 enforcement date. AEP recommends that the version 2 enforcement date should have the exact same enforcement date as in version 1 for those assets already explicitly in scope under version 1. As an example, the table below shows what would happen if the effective date for version 2 of PRC-025 were to be June 1 of 2018. As shown in the table provided, the version two enforcement dates for assets already explicitly in scope under version one, both for assets where no removal or replacement is necessary *and* for assets requiring removal or replacement, would be sooner that their corresponding enforecement dates under version one.

Requirement	Effective Date	Enforcement Date
PRC-025-1 R1 (No removal or replacement necessary)	10/01/14	10/01/19
PRC-025-**2** R1 Assets Already Explictly in Scope (No removal or replacement necessary)	06/01/18	06/01/19
PRC-025-1 R1 (Requires removal or replacement)	10/01/14	10/01/21
PRC-025-**2** R1 Assets Already Explictly in Scope (Requires removal or replacement)	06/01/18	05/31/21

AEP has chosen to vote negative on the proposed draft of PRC-025-2, driven by our concerns related to the proposed implementation plan.

Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The Implementation Plan should not require taking a special outage for PRC-025, and should therefore allow at least five years to make relay settings changes, and seven years to install new devices.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The Implementation Period should align with the existing Implementation Period of PRC-025-1 because that is what utilities have been working toward.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
As currently written, it appears the implementation plan can actually shorten the current timeframes to become compliant with PRC-025. If PRC-025-2 was approved and became effective prior to 10/1/18, entities would have less time to comply with the 2 scenarios under "Load-responsive protective relays subject to the standard" in the implementation plans. Currently entities have until 10/1/19 to comply when they will be making a setting change to meet the setting criteria and 10/1/21 to comply when they will be removing/replacing the relay to meet the setting criteria. Tri-State recommends adding	

language similar to the commonly used "shall become effective on the later of XXXX or the first day of the XX calendar quarter". That would prevent entities from losing time they might have already planned on having to become complaint with PRC-025-1. Additionally, can the SDT explain why they changed the timeframes (from 60 and 84 months to 12 and 36 months respectively) under "Load-responsive protective relays subject to the standard" but not the ones under "Load-responsive protective relays which become applicable to the standard" provided in the implementation plans.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Implementation Period should align with the existing Implementation Period of PRC-025-1 because that is what utilities have been working toward.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
The Implementation Plan should not require taking a special outage for PRC-025, and should therefore allow at least five years to make relay settings changes, and seven years to install new devices.	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	

Answer	No
Document Name	
Comment	

TVA does not agree that a 12-month implementation period is sufficient for changes to relay settings that now may be required due to the new applicability of the 50 (instantaneous overcurrent) element in PRC-025-2 Draft 1. The original PRC-025-1 implementation plan allowed 5 years from approval to implement settings changes. This 5-year period was sufficient for implementing new relay settings, even for nuclear units which are tied to refueling outage schedules. TVA has seven nuclear units. Some other entities have even more. It is unreasonable to expect nuclear units to schedule additional outages that could be required within the proposed 1-year implementation period, just to perform relay settings changes.

Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	
Comment	

The current standard's implementation plan states that the entity must be compliant by October 2019, or by October 2021 for the removal or replacement of applicable relays. The proposed implementation plan only identifies the retirement of the previous standard and does not provide a

transition period between revisions. We propose incorporating a clause that begins the compliance period no earlier than October 2019, and no earlier than October 2021 for the removal or replacement of applicable relays.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Unless the SDT clarifies that the PRC-025 applicability section refers only to PRC-025 relays on 1) substation Bulk Electric System (BES) elements and 2) individual power producing resource relays at the BES generators, and that all collector system protective relays are excluded, the first implementation of PRC-025-1 was not clear and entities will need 60 months to staff and build systems to support zero-defect compliance monitoring and change management.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
It would be beneficial for maintenance requirement to align with PRC-005 maintenance requirement since time between scheduled outages for generation units can be as long as 36 months.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	

Answer	No
Document Name	
Comment	
The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG recommends changing the implementation plan since there is no correlation between the number of the relays requiring replacement and the arbitrary implementation period. We suggest the implementation period to be a function of the number of relays involved. Alternate graded approach is also possible i.e. 25, 50, 75 & 100% corresponding to 5 years.	
Likes 0	
Dislikes 0	
Response	

Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The proposed Implementation Plan is consistent with the timelines for compliance with PRC-025-1. Texas RE suggests the SDT clarifies that entities making a determination that replacement or removal is necessary, triggering the 36-month compliance window, should document those conclusions.	
Likes 0	
Dislikes 0	
Response	

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Stating that this is a severe VSL and high VRF is way more severe than the actual risk for not being in compliance with PRC-025-2 especially for asynchronous generators. If the settings and studies are done correctly there is no risk of false tripping even if the pickups are not as high as the requirements in this standard.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends there is a need for high/moderate/low VSLs based on the number of relays impacted by the standard. Reclamation recommends a VSL similar to that for PRC-005-6 R3 and R4. Reclamation recommends the following VSLs: Requirement Number - R1 Lower VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on fewer than 5% of its load-responsive protective relays. Moderate VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 5% to less than 10% of its load-responsive protective relays. High VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 10% to less than 15% of its load-responsive protective relays. Severe VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 15% or more of its load-responsive protective relays.	

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe a performance-based criteria could be established for the Violation Severity Levels for this standard, similar to what is present for NERC Reliability Standard PRC-005-6. In that standard, the severity is based on a specific percentage of Components the applicable entity failed to maintain in accordance with minimum maintenance activities and maximum maintenance intervals. We recommend using the same criteria for this standard.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	

Comment
Likes 0	
Dislikes 0	
Response
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC
Answer	Yes
Document Name	
Comment
Likes 0	
Dislikes 0	
Response
Normande Bouffard - Hydro-Qu?bec Production - 5
Answer	Yes
Document Name	
Comment
Likes 0	
Dislikes 0	
Response
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC
Answer	Yes
Document Name	
Comment
Likes 0	

Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends changing the “and” to an “or”. Additionally, Texas RE requests the SDT consider providing a justification of the “Long Term Planning” time horizon as it has a significant impact on Penalty calculations.	
Likes 0	
Dislikes 0	
Response	

9. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
These options, and other options, which use the phrase “gross MW reported to the Transmission Planner” needs clarity. That values are reported to the Transmission Planner annually. These values change somewhat, annually. Should Transmission Owners re-evalute that data and the settings derived from that data annually? I believe the spirit of PRC-025 is met with a one-time implmenetation based on this generator data. There should be no burden on Transmission Owners to re-evaluate this geneator data every year and re-calculate setitngs every year. Even if the Transmission Owner chooses to calculate settings on data more conservative than what is reported to the Transmission Planner, there should not be a requirement against annually chaning data.	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Entities that took NERC at their word in performing calculations and (where necessary) making changes under PRC-025-1 should be “grandfathered” for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	No

Document Name	
Comment	
See comments and alternative approaches to meet the intent of the Standard in response to Question 2 above.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Entities that performed calculations per NERC guidance and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.r	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources. The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	

Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe the standard is too inclusive of all load-responsive protective relays. The applicability of this standard should be reflective of other PRC Standards, such as NERC Reliability Standard PRC-019-2, and based on the BES definition and gross nameplate ratings of generation Facilities.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Cost efficiency would be achieved by focusing on the correct impactful objectives, such as common-mode design issues, while excluding zero-defect compliance monitoring/change management for individual collector systems or individual dispersed power producing resources. For example, without an outside source to provide internal capability curves, Option 5 may be extremely labor intensive to develop and maintain to zero-defect. Zero-defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. Reclamation recommends the SDT modify the applicability section to concentrate on common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. This appropriately focuses compliance efforts on the measurable impacts of common-mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources. The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

10. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict here.

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends that the SDT check to see if the inclusion of collector systems could infringe on state jurisdictions.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.	
Likes 0	

Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	No
Document Name	
Comment	
No from a technical point of view, but there might be some regional variances with the version approved by the Regie de l'Énergie du Québec.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
George Brown - Acciona Energy North America - 5	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

11. Are you aware of a need for a regional variance or business practice that should be considered with this project? If yes, please identify the need here.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE requests this question be included for each project.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Hydro-Québec TransÉnergie has proposed calculations and simulations for a particular configuration.	

Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
It would be beneficial for maintenance requirement to align with PRC-005 maintenance requirement since time between scheduled outages for generation units can be as long as 36 months.	
Likes 0	
Dislikes 0	
Response	

12. If you have any other comments on this Standard that you haven’t already mentioned above, please provide them here:	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	
I was not able to log my vote in SBS despite being in the ballot pool and attempting to vote affirmative before the ballot close time. Please contact me to ensure this issue is remedied.	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
Applicability Section 4.1 references "3.2, Facilities." This appears to be a typographical error; consider correcting to reference "4.2 Facilities.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
All settings should be based off load ability and equipment ratings like option 5b allows. Setting elements to arbitrary values called out in PRC-025 is not good sound engineering and poor practice for protecting electrical equipment. Settings should be based on IEEE standards and studies preformed by the professional licensed engineer developing the settings.	

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	
Document Name	

Comment

Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.

For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 “protective elements” or devices (which can be more than relays) expected by the PRC-025 drafting team.

As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three “protective elements” or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more “protective elements” or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the “smart crowbar” example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.
5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.
6.

In this 3,000 wind turbine example there are 21,300 “protective elements” to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to

12,300 devices to track and coordinate. This doesn't include the substation System Protection devices that we already consider at the substation.

What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues?

Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solution:

1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

Replace the proposed Applicability section 3.2.5

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

With:

3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining "Protective element" for PRC-025 means, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as:

Collector System: Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of “Element” and “Facility” to separate plant issues from individual generator issues (thanks to Darnez for this item):

NERC Defined Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Defined Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Figure examples should be added to show examples of “elements utilized in the aggregation of dispersed power producing resources” for clarity as the BES definition excludes these elements from the BES.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	
Document Name	

Comment
Reclamation recommends the SDT clarify the definition of Unit Auxiliary Transformer (UAT) in footnote 1 on page 3 of 112 of the standard to state that a Unit Auxiliary Transformer does not include excitation supply power potential transformers. Reclamation recommends the SDT clarify what benefit is derived from zero-defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues. Reclamation recommends the SDT clarify the definition of Unit Auxiliary Transformer (UAT) in footnote 1 on page 3 of 112 of the standard to state that, “a Unit Auxiliary Transformer does not include excitation supply power potential transformers.” For clarity, Reclamation recommends the SDT state the PRC-025 “protective elements” or devices (which can be more than relays) expected to be in scope. Reclamation recommends the SDT evaluate the impact of PRC-025 in terms of the number of PRC-025 devices, similar to the impact of PRC-005. All of these items (and potentially more, based on the recent NERC Lesson Learned, “Loss of Wind Turbines due to Transient Voltage Disturbances on the Bulk Transmission System”) would have to be tracked for zero defects, such as perfect settings and perfect knowledge of changes. This could result in an entity’s PRC-025 program being the same or greater size and workload as its PRC-005-6 program. Following are some possible solutions to help focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements. **Proposed Solutions:** 1. Reclamation recommends that the drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more and the loss of individual collectors or individual generators. Reclamation recommends replacing the proposed Applicability section 3.2.5 *3.2.5 Elements utilized in the aggregation of dispersed power producing resources.* with: **3.2.5** Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event. **3.2.6** Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified in 3.2.5. 2. Reclamation recommends that the drafting team consider defining “protective element” as, “protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system.” A protective element excludes fuses. 3. Reclamation recommends that the drafting team consider adding a NERC Glossary defined term of “Dispersed Power Producing Resource Collector System” such as: **Collector System:** Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above. 4. Reclamation recommends that the drafting team consider modifying the existing NERC Glossary definitions of “Element” and “Facility” to separate plant issues from individual generator issues as follows:

Element: Any electrical device with terminals that may be connected to other electrical devices such as *an individual generator, an individual dispersed power producing resource*, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a *generating plant or aggregate dispersed power producing plant*, a shunt compensator, transformer, etc.)	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
1. Section 4.1 identifies functional entities that are applicable to this standard. These entities apply load-responsive protective relays at the terminal ends of the Elements identified in Section 3.2, Facilities. However, we believe the applicability of these Facilities are listed under Section 4.2. We observe this inconsistency throughout the standard. 2. This project continues to run independent of the current implementation plan identified for NERC Reliability Standard PRC-024-1. Although the phased-in implementation of this standard is still on-going, it very probable that a registered entity has already developed a complete compliance program that addresses the current version of this standard. We simply ask the SDT to acknowledge this possibility. 3. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	Project 2016-04 PRC-025-2Final.docx
Comment	
Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT. For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 “protective elements” or devices (which can be more than relays) expected by the PRC-025 drafting team. As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three “protective elements” or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side	

fuse potentially creating three more “protective elements” or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the “smart crowbar” example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.

2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.

3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.

4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.

5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.

In this 3,000 wind turbine example there are 21,300 “protective elements” to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn’t include the substation System Protection devices that we already consider at the substation.

What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues

Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solution:

1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

Replace the proposed Applicability section 3.2.5

3.2.5 Elements utilized in the aggregation of dispersed power producing resources

With:

3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining "Protective element" for PRC-025 means, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as:

Collector System: Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of "Element" and "Facility" to separate plant issues from individual generator issues (thanks to Darnez for this item):

NERC Defined Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Defined Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)

Please see attached document for diagram.

Likes 0	
Dislikes 0	

Response

M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

Several times the term "Real Power output" is defined in the proposed standard as "100% of the aggregate generation gross MW capability reported to the Transmission Planner." TVA believes that it can be difficult to determine what is meant by "capability reported to the transmission planner," and would like to see the standard clarify on which reporting mechanism or process this generation capability is normally expected to be based. A Transmission Planner can have multiple capabilities reported for one unit. For example, a MOD-025 capability verified by test or operational data, versus a planned capability that reflects a modification to be implemented in the near future.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	
Table 1 seems to explicity require specific reach settings and does not address how to comply with the standard if using a quad element and not a mho element, even though a quad element is uncommon in generator relays. Additionally, there is not a clear path in the standard regarding load encroachment blocking. Load encroachment blocking is mentioned in the PRC-025-1 Application Guideline and the the NERC SPCS report "Considerations for Power Plant and Transmission System Protection Coordination" but is absent in the standard.	
Likes 0	
Dislikes 0	
Response	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
In Table 1, Relay Type column, for Options 14, 15, 16, 17, 18, and 19, consider changing "…installed on the high-side of the GSU transformer and [on the] remote end of the line" to something like "…installed on the high-side of the GSU transformer and/or [on the] remote end of the line" or "…installed on the high-side of the GSU transformer, including [on the] remote end of the line." A simple 'and' suggests that relaying at both locations may be required.	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	

The SDT should modify the applicability section to concentrate on common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded as in PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE inquires about the use of the Application Guideline as there are several changes in the works with regards to attached documents. Texas RE's understanding is that any guidance as to how to comply with a standard will go through the Implementation Guidance process. Any technical basis will be in a Technical Rationale document. How does the Application Guidance in PRC-025-2 fit in with the new schematic? In addition, Texas RE requests the technical reason that the GO might provide a base setting on capability that is higher than what is reported to the Transmission planner, as noted in Attachment 1. Texas RE also noticed the following grammatical issues/typos: • The header still has "-1" throughout Standard. • Applicability section 4.1 references "3.2, Facilities" which does not exist. It should reference "4.2, Facilities". • Facility section 4.2.4 has two sentences that conflict. The first sentence says "used exclusively to export"; the second sentence says "may also supply". If an element is used exclusively for something, that precludes it from also including something else. • The Compliance Monitoring Process section is incorrectly numbered as "8" (and subparts 8.1, 8.2, etc.).	
Likes 0	
Dislikes 0	
Response	

Ruth Miller - Exelon - 5	
Answer	
Document Name	
Comment	
None. Thank You	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
As written, NERC Reliability Standard PRC-025-2 Generator Relay Loadability does not account for equipment limitations of the generator step-up transformer or generation lead line that would not allow an entity to set it's protective relays to the level as specified within the standard. The SDT needs add additional option for these application that is similar to option 5B.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	
Document Name	
Comment	
Tri-State would like to point out that there seems to be an error in "Section 4.1 Functional Entities" where the sub bullets are referencing section "3.2, Facilities." That should be "4.2, Facilities."	
Likes 0	

Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG recommend that instead of “relay location” to use “relay associated instrument transformers (PT’s/CT’s) location”. Clarification are recommended for the cases where the protective device settings are not achievable due to additional possible constrictions related to the supply path associated equipment. This can be achieved by defining the “resource” in Option 5b.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	
Document Name	
Comment	
Please clarify if switch-onto-fault is meant to be included in Attachment 1: Relay Settings. Exclusion #1 states, “Any relay elements that are in service only during start up.” Is switch-onto-fault included as an element that is only service during start up? PRC-023 specifically addresses switch-onto-fault in Attachment A as applicable to the standard; addressing switch-on-to-fault in PRC-025 would provide consistency and clarity between the two similar standards.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	
Document Name	

Comment	
Section 4.1 (Functional Entities) references the Elements listed in Section 3.2 (Facilities); however, Section 3.2 (Facilities) does not exist within the PRC-025-2 – Generator Relay Loadability proposed standard document. Section 4.1 (Functional Entities) should instead be updated to reference the Elements listed in Section 4.2 (Facilities).	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy recommends the drafting team consider adding another option (perhaps 13c) that would address the high side UAT overcurrent settings under this standard. We suggest adding: *"Where there is only one UAT low side protective device that is set at a minimum 135% of the UAT nameplate or 135% or greater than load operating at .85 per unit voltage, the UAT high side protective device must be set equal to or coordinate with the low side protective device."* The issue this would address is the prudent protection settings and compliance of the high side overcurrent with the standard. In some instances, the high side overcurrent is coordinating with the low side overcurrent. Currently, there is nothing that is addressing the low side. We feel that this is a technical flaw in the standard, which should be addressed.	

Also, there are some instances where some BES UAT's with high side fuses will operate at less that 150% UAT ratings. Based on these instances, we feel that fuses should be considered as an addition to the relay type category. We suggest that the drafting team consider making the changes referenced above to correct the technical errors, or remove references to the UAT in the standard altogether.	
Likes 0	
Dislikes 0	
Response	
Tom Haire - Rutherford EMC - 3	
Answer	
Document Name	
Comment	
Section 4.2.5 should have a minimum threshhold. Section 4.1 should reference 4.2 not 3.2	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP has chosen to vote negative on the proposed draft of PRC-025-2, driven by our concerns related to the proposed implementation plan (detailed in our response to Q7). AEP recommends a more appropriate per unit voltage level of 0.85 per unit, rather than 1.0 per unit, for options 13a, 13b, 17, and 18 within Table 1. In the Applicability section, all references to "3.2, Facilities" should instead be "**4**.2, Facilities."	
Likes 0	
Dislikes 0	

Response

Additional comments/information received from Russel Mountjoy – MRO NSRF

Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

   ☐ Yes

   ☒ No

   Comments: Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solare facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instanteous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

   ☐ Yes

   ☒ No

   Comments: The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements" please add the word "PRC-025 relay" in front to clearly state that only "PRC-025 relays" are applicable, not control systems, not protective algorithms, and not fuses.

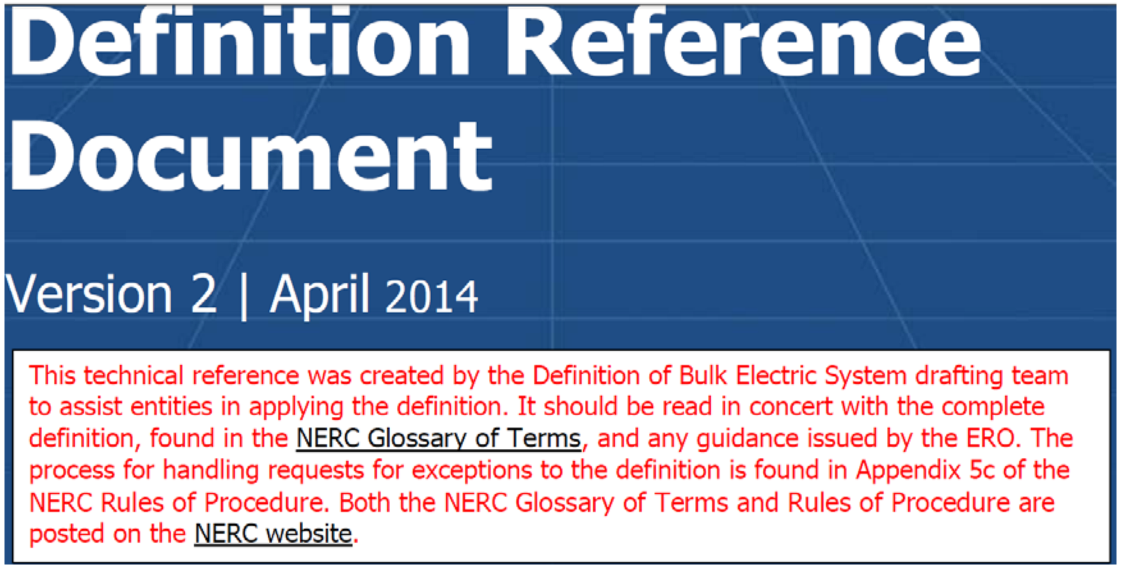
   If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments: No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85.


Definition Reference Document

Version 2 | April 2014

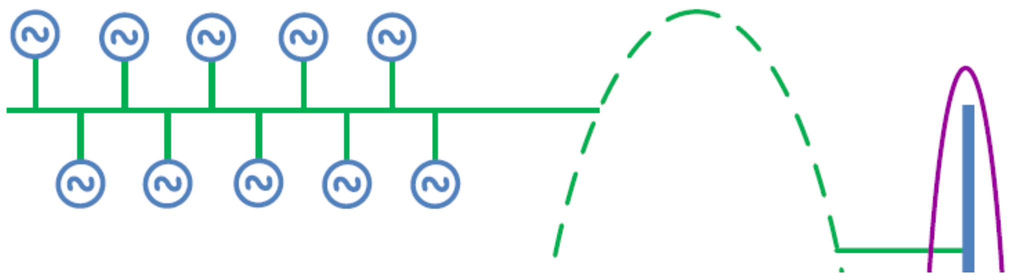
This technical reference was created by the Definition of Bulk Electric System drafting team to assist entities in applying the definition. It should be read in concert with the complete definition, found in the NERC Glossary of Terms, and any guidance issued by the ERO. The process for handling requests for exceptions to the definition is found in Appendix 5c of the NERC Rules of Procedure. Both the NERC Glossary of Terms and Rules of Procedure are posted on the NERC website.

Figure I4-2 depicts a dispersed generation site and substation design with unknown collector system configuration.

Typical dispersed generation site and substation design (single transformation of voltage level) with a gross aggregate nameplate rating of 80 MVA (Individual Generator Unit Rating: 2 MVA). By application of Inclusion I4 the dispersed power producing resources and the Elements from the point of aggregation to the common point connection are BES Elements.

Green indicates the portions of the Collector System that are not included in the BES.

Blue identifies the dispersed power producing resources and BES Elements between the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.



Link:

http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

Please state that Technical Guidance is for examples only, guidance isn't enforceable and cannot alter the scope of compliance.

4. Do you agree that the proposed revisions in Table 1 for Options 14 thorugh 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

☒ Yes

☐ No

Comments:

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments:

The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing “Pickup”. Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

☒ Yes

☐ No

Comments:

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement **is not** necessary, and (2) 36 months where equipment removal or replacement **is** necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

☐ Yes

☒ No

Comments: No. The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

☒ Yes

☐ No

Comments:

9. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e.,

Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

☐ Yes

☒ No

Comments: Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources.

The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6.

This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.

10. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If **yes**, please identify the conflict here.

☐ Yes

☒ No

Comments: No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.

11. Are you aware of a need for a regional variance or business practice that should be considered with this project? If **yes**, please identify the need here.

☐ Yes

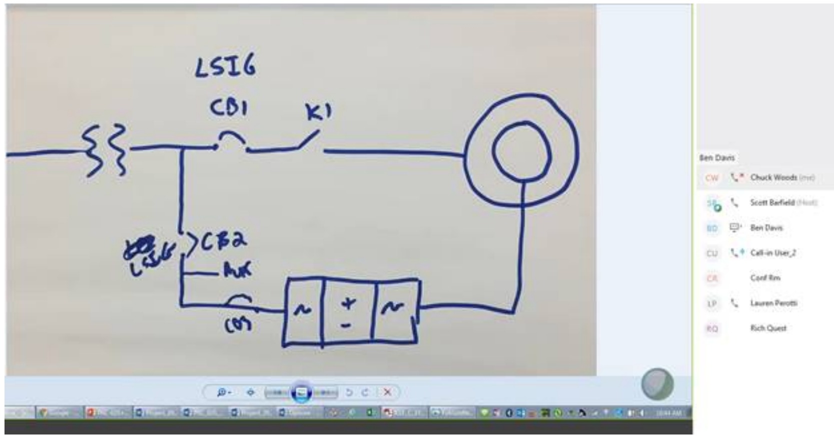
☒ No

Comments:

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

Comments:

Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.



For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 “protective elements” or devices (which can be more than relays) expected by the PRC-025 drafting team.

As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three “protective elements” or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more “protective elements” or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the “smart crowbar” example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.
5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.

In this 3,000 wind turbine example there are 21,300 “protective elements” to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn’t include the substation System Protection devices that we already consider at the substation.

What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues?

Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solution:

1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

   Replace the proposed Applicability section 3.2.5

   ~~*3.2.5 Elements utilized in the aggregation of dispersed power producing resources.*~~

   With:

   3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

   3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining "Protective element" for PRC-025 means, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as:

   Collector System: Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of "Element" and "Facility" to separate plant issues from individual generator issues (thanks to Darnez for this item):

   NERC Defined Element: Any electrical device with terminals that may be connected to other electrical devices such as ~~a generator~~, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Defined Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a ~~generator~~ generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)

Consideration of Comments

Project Name: 2016-04 Modifications to PRC-025-1 | PRC-025-2
Comment Period Start Date: 7/25/2017
Comment Period End Date: 9/8/2017

There were 43 sets of responses, including comments from approximately 127 different people from approximately 96 companies representing the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Summary Consideration

The vast majority of stakeholders were supportive of the revisions. There were a number of clarifying suggestions that the standard drafting team (SDT) incorporated into the documents, but more importantly the SDT revised the Implementation Plan to allow for phased-in effective dates.

The SDT made a minor revision in Option 5b to improve clarity based on stakeholder comment. A footnote was added to the Applicability section to bring attention that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." The SDT revised Figure A based on comments and added a new Figure 4 in the Application Guidelines to illustrate Elements utilized in the aggregation of dispersed power producing resources (e.g., collector system or feeders). The relay location information in the Relay Type column of Table 1 was moved to the Application column to make the table content more consistent with the text in each column. There were no justification changes to the VRF/VSL Justification when the SDT updated the document to the new NERC template.

The Implementation Plan was revised so that the PRC-025-2 Implementation Plan will supersede the PRC-025-1 Implementation Plan. The intent is to prevent instances of non-compliance under Table 1 Option 5 of PRC-025-1 that could result in self-reporting while not unreasonably extending the original effective dates. The Table 1 Options that now include the 50 element will have phased-in dates that occur 60 months for setting changes and 84 months for equipment replacement or removal after approval. Other minor revisions in the Table 1 Options as outlined in the Implementation Plan will have phased-in dates that occur at 24 and 48 months likewise.

The Application Guidelines were not removed from the standard. The separation of the Application Guidelines from the standard is anticipated to be done under a later NERC project focused on addressing standards containing forms of implementation guidance.

fa

Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instantaneous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

4. Do you agree that the proposed revisions in Table 1 for Options 14 through 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement is not necessary, and (2) 36 months where equipment removal or replacement is necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

8. **Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.**

9. **Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.**

10. **Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict here.**

11. **Are you aware of a need for a regional variance or business practice that should be considered with this project? If yes, please identify the need here.**

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

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Ryan Strom	Buckeye Power, Inc.	4	RF
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Con-Edison	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Québec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Québec	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

Question 1	
1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
More clarity is needed on the implementation of Option 5b. “Resource capability” should be defined such that this value can be clearly determined. A detailed example for Option 5b which uses a plot similar to Figure A that discusses “documented tolerances” would be helpful.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Resource capabilities do not have tolerances associated with them.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The overcurrent element setting of 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor is appropriate in most cases. Texas RE recommends keeping the 130% threshold for overcurrent elements and allow for exceptions in those cases where entities are limited by manufacturer requirements or physical limitations.	

Question 1	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Option 5b is essentially an exception based option for inverter based machines that cannot achieve the 130% threshold due to equipment limitations.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solar facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.	
Likes 1	Jeffrey Watkins, N/A, Watkins Jeffrey
Dislikes 0	
Response	
Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Question 1	
Option 5b is helpful and a clear improvement. In addition, Reclamation recommends that Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the generator will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement. Or, as approved in PRC-024-2, if Option 5 cannot be satisfied for older equipment, a statement such as, “Document the identification of regulatory or equipment limitations.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity’s approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
Option 5b is helpful and a clear improvement. However, Option 5b isn’t a complete solution. Not all solar and wind facilities are new. Some wind / solare facilities won’t have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.	
Likes 0	
Dislikes 0	
Response	

Question 1	
Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
What is the need for option 5a with 5b being an option? Option 5b shows the correct way protective relays should be set and coordinated with equipement. If the protection can be set above the capability of the equipement output, what would be the reason to set the pickups at 130% above MVA unless you want a fault to cause more damage to the equipement being the clearing time could be delayed?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Option 5a was left to allow entities that have implemented to continue using the option. The options provide a minimum thresholds to set load-responsive protective relays for depressed voltages based upon 0.85 per unit nominal voltage. The standard is not addressing protection for longer periods that would protect against sustained low voltage or over loading.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group has a concern that Figure A (page 32 redline version) doesn't provide enough clarity on its purpose in reference to Option 5b. Additionally, we have a concern that the figure is missing the appropriate labeling methodology. We would ask	

Question 1	
the drafting team to provide more clarity in the Application Guideline Section of the Standard in reference to the figure's significance to Option 5b as well as including the appropriate labeling methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team modified Figure A and the Table 1, Option 5b, Setting Criteria to be consistent.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP recommends the SDT use the same frame of reference for both the Option 5a in Table 1 and Figure A. As currently written, Table 1 states "The overcurrent element shall not infringe upon…" while Figure A states "Option 5b – Resource capability shall not infringe on…".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team modified Figure A and the Table 1, Option 5b, Setting Criteria to be consistent.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG is of the opinion that there is a discrepancy between the Relay setting criteria description for option 5b in Table 1 and the description contain in the Figure A, which should be corrected. Instead of "Option 5b – Resource Capability shall not infringe on the lower	

Question 1	
tolerance of the protective device" we recommend Figure A should state the following "Option 5b – Protective device overcurrent element settings lower tolerance tripping characteristic shall not infringe on the Resource capability" Additional clarification is required regarding if asynchronous resource capability accounts for forcing & boosting effects on the steady state fault current (not the subtransient and transient).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team modified Table 1, Option 5b, Setting Criteria similar to the suggestion in the comment. The last comment is out of scope of the standard because the capability corresponds to 1.0 per unit voltage.	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
As written, NERC Reliability Standard PRC-025-2 Generator Relay Loadability does not account for equipment limitations of the generator step-up transformer or generation lead line that would not allow an entity to set it's protective relays to the level as specified within the standard. The SDT needs add additional option for these application that is similar to option 5B.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Equipment limitations for other applications in Table 1 have not been identified by industry.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Question 1	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	

Question 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 1	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	

Question 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 1	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes

Question 1	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Not applicable to BPA.	
Likes 0	

Question 1	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Question 2	
2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instantaneous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements" please add the word "PRC-025 relay" in front to clearly state that only "PRC-025 relays" are applicable, not control systems, not protective algorithms, and not fuses. If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had already revised locations regarding "element" and "relay" to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard.	

Question 2	
The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." Individual generator control systems are outside the scope of the drafting team's revisions.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but "pickup" was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements," Reclamation recommends the drafting team insert the words "PRC-025 relay" to clearly state that only PRC-025 relays are applicable, not control systems, protective algorithms, or fuses. If the drafting team meant to include more protective elements than relays, Reclamation recommends that the standard clearly state the applicable protective elements. This standard is written to zero-defect and subject matter experts must clearly understand where it does and does not apply. Unless the standard allows some room for a small amount of error to be corrected, the compliance thresholds must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had already revised locations regarding "element" and "relay" to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	

Question 2	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements" please add the word "PRC-025 relay" in front to clearly state that only "PRC-025 relays" are applicable, not control systems, not protective algorithms, and not fuses. If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had already revised locations regarding "element" and "relay" to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	

Question 2	
67 and 50 elements/relays should be out of scope due to the possibility of creating a protection sheme that may not pick up when it should. See comments from Exelon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 67 and 50 elements should be in scope as they can be susceptible to tripping under certain loadability conditions. Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	

With respect to phase directional instantaneous overcurrent supervisory elements (67 or 50) – associated with current-based communication protection systems please consider the following

1. These relays will be affecting loading/generator loadability only if communication system fail and there is a disturbance on the grid. The Standard should not assume both events at the same time.

2. Calculations performed to calculate the settings for these type of relays show that the settings are very close to the 3-phase fault current contributed from the generator in cases where sub-transient reactance of the machine is at a high value. This will compromise the protection scheme because the changes proposed will make the protection scheme very insensitive. In case of a high resistance phase-to-ground fault, the protection scheme will not pick up the fault at the generator end. In some extreme cases, the fault detector relay (67 or 50), if set according to the current draft PRC-025 guidelines, may have to depend on the field forcing provided by the Automatic Voltage Regulator (AVR) before the fault current reaches the setpoint. This will induce unnecessary delays in the protective action and may cause more damage to the BES element.

Question 2	
3. Exelon proposes the following changes: i. These types of relays (67 or 50) should be deleted from the scope of this Standard for the reasons described above. ii. If there is an issue with communication protection systems such that the pilot protection scheme acts like a simple overcurrent relay, and that condition is alarmed, then it is reasonable to require an entity to correct this condition within a short period of time. Suggest the SDT add a requirement to correct such a condition within a certain timeframe. For example the condition shall be corrected within a calendar quarter and if not resolved then the setpoints of 67 or 50 should be raised to a certain value. iii. If SDT still wants to keep these relays within scope in spite of the reasoning/alternatives provided above, the the existing setting criteria the following should be added: "Minimum of the criteria 15a (or 15b) or 25% of the sub-transient current contribution from the generator using a pre-fault voltage of 1.0 and generator sub-transient unsaturated reactance and the main power transformer positive sequence reactance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. Based on the drafting team's experience, a communication system failure could last for an extended period of time. This will increase the possibility that a disturbance could occur during the communication failure. 2. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the [Standards Authorization Request](http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf) (SAR).[1] Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	

[11] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 2	
3. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the [Standards Authorization Request](http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf) (SAR).[2]	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Unfortunately, the addition of "e.g." does not add clarity. The SDT needs to clearly state what protection function each option in Table 1 applies to.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team provided this change to allow a level of technology neutrality on IEEE/ANSI device numbering. For example, for the 51 V-R relay the Application Guidelines note that these protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

[22] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 2	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Question 2	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 2	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes

Question 2	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 2	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	

Question 2	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 2	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Question 2	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 2	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 2	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Question 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 2	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes

Question 2	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
***3.** Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.*	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of "Element" (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	

Question 3	
Answer	No
Document Name	Project 2016-04 PRC-025-2Final.docx
Comment	
No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85. Link: http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf Please state that Technical Guidance is for examples only, guidance isn't enforceable and cannot alter the scope of compliance. See attached document for diagrams.	
Likes 1	Jeffrey Watkins, N/A, Watkins Jeffrey
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The Guidelines and Technical Basis will be evaluated by NERC for removal from the standard and for placement in a separate document under a Standards department project.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No

Question 3	
Document Name	
Comment	
Figure 3 of the Guidelines and Technical Basis section discusses the inclusion of collector system protective elements; however, the NERC defined term "Element" specifically excludes collector systems in accordance with the NERC bulk Electric System Definition Reference Document dated April 2014; see page 21 of 85. http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf Reclamation recommends that the Guidelines and Technical Basis document state that it is an example only and is not enforceable, or remove the discussion on collector system protection elements. If the drafting team intended to include collector system protective elements for zero-defect compliance monitoring and change management, Reclamation recommends the standard be revised to clearly state "PRC-025 collector system" or "PRC-025 collector system relay elements" throughout the standard, including the Applicability Section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of "Element" (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition. The Guidelines and Technical Basis will be evaluated by NERC for removal from the standard and for placement in a separate document under a Standards department project.	

Question 3	
Thank you for your comment. The scope of the drafting team's work is to revise PRC-025-1 as described in the [Standards Authorization Request](http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf) (SAR).[3]	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of "Element" (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition.	

[33] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 3	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
It is an improvement and adds additional clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Question 3	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Question 3	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Question 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 3	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes

Question 3	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 3	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Question 3	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Question 3	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	

Question 3	
Likes 0	
Dislikes 0	
Response	

Question 4	
4. Do you agree that the proposed revisions in Table 1 for Options 14 through 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
While it is not typical for a generator to be rated higher than the line connecting the GSU to the transmission system, PSE has concerns with setting the relays for the line based on the generator ratings. Protective relays should be set according to the equipment that they are intended to protect (i.e. line relays should be set to protect the line, transformer relays should be set to protect the transformer, and generator relays should be set to protect the generator). Setting a line relay to protect a generator, particularly when the line might be rated lower than the generator could result in damage to the line, and could potentially result in reduced reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The settings should not inhibit the output of the generator for the conditions anticipated by the standard and should be properly set to provide adequate fault protection of the respective equipment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Question 4	
No because if you have multiple radial lines exporting the power from a generator, each line may not have the capability of carry the full power output of the generator. Engineers should have the ability to study individual installations and set the protection correctly for the equipment installed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The issue of multiple lines leaving a plant is addressed in the existing and proposed standard under the heading “Multiple Lines” in PRC-025-2 – Attachment 1: Relay Settings.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Entities that performed calculations per NERC guidance and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any revisions proposed that would require an entity to re-perform calculations in order to become compliant with the standard.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	

Question 4	
Comment	
Tri-State would like clarification on the phrase "and on the remote end of the line" used in the Relay Type column of Option 14. Looking at the red-lined language under "Figure 1" of the guidelines section, our understanding is that relay R3 is applicable only if it is set with an element directional toward the transmission system or is non-directional. If relay R3 is set directed toward the generator, it is not applicable. If that is the case we recommend splitting up the language between the 2 scenarios and adding a figure to make it clear. As it is currently written, it isn't clear that only the 1st of those scenarios is displayed in Figure 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team does not agree the suggestion to split the example into a second Figure would add clarity.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Entities that took NERC at their word in performing calculations and (where necessary) making changes under PRC-025-1 should be “grandfathered” for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any revisions proposed that would require an entity to re-perform calculations in order to become compliant with the standard.	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	

Question 4	
Answer	No
Document Name	
Comment	
While it is not typical for a generator to be rated higher than the line connecting the GSU to the transmission system, PSE has concerns with setting the relays for the line based on the generator ratings. Protective relays should be set according to the equipment that they are intended to protect (i.e. line relays should be set to protect the line, transformer relays should be set to protect the transformer, and generator relays should be set to protect the generator). Setting a line relay to protect a generator, particularly when the line might be rated lower than the generator could result in damage to the line, and could potentially result in reduced reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The settings should not inhibit the output of the generator for the conditions anticipated by the standard and should be properly set to provide adequate fault protection of the respective equipment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
This sentence is confusing: “Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing” Consider changing to: “Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing”???	
Likes 0	
Dislikes 0	

Question 4	
Response	
Thank you for your comment. The drafting team applied the suggestion to Options 14b, 15b, and 16b.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes

Question 4	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 4	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	

Question 4	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 4	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	

Question 4	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 4	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Question 4	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 4	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Question 4	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	

Question 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	
Document Name	
Comment	
N/A	

Question 4	
Likes 0	
Dislikes 0	
Response	

Question 5	
5. ***Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.***	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
The term "pickup" clearly indicates what part of the overcurrent device setting needs to meet the criteria. Perhaps this term can be retained for current operated devices.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of "Pickup" from the standard as scoped in the SAR and agrees that "Settings Criteria" is a more appropriate term for the value. It aligns with the intent of the standard for relays to not trip based on the criteria in Table 1.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
"Pickup" setting indicates the minimum operating value. Please retain the leading term "Pickup".	
Likes 0	

Question 5	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing “Pickup”. Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.”	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Question 5	
Answer	No
Document Name	
Comment	

If Pickup is not removed:

Reclamation recommends the SDT provide clarifying language describing what removing “Pickup” means. Pickup for PRC-025 refers to “PRC-025 Relays,” meaning actual relays at the individual generators with pickup settings. This does not include 1) any individual generator control systems, 2) collector system protective relays that may be installed on the padmount transformers, or 3) collector system protective relays on the radial collectors at the collector substation.

If Pickup is removed:

Reclamation recommends the SDT decide what protective relays are to be included and explicitly specify them. The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drafting team is looking for protective elements in addition to relays. If the SDT intends to include more than PRC-025 protective relays, the applicability criteria must be adjusted in addition to removing “Pickup.”

Reclamation recommends the PRC-025 Applicability section should specifically reference 1) individual generator control systems that may trip the individual power producing resource, 2) collector system protective relays that may be installed on the padmount transformers, or 3) collector system protective relays on the radial collectors at the collector substation.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1.

Question 5	
The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." On item (1) Individual generator control systems are outside the scope of the drafting team's revisions, and items (2) and (3) they are already applicable per the Applicability section 4.2.5.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The applicability section states that PRC-025 applies to relays. Removing "Pickup" suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing "Pickup". Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of "Pickup" from the standard as scoped in the SAR and agrees that "Settings Criteria" is a more appropriate term for the value. The use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to "not trip" based on the criteria in Table 1. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No

Question 5	
Document Name	
Comment	
The setting that has to be met per the standard is the pickup setting, the standard does not talk about timing, just pickup, so why remove pickup from the table.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
It would provide added clarity to include “non-directional” in front of “phase instantaneous overcurrent supervising elements (e.g. 50)” and “phase time overcurrent relay (e.g. 51)”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The devices 50 and 51 are defined as non-directional elements. Further clarification would be redundant.	
Ruth Miller - Exelon - 5	

Question 5	
Answer	Yes
Document Name	
Comment	
See comments provided in the response to Question 2 above.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

1. Based on the drafting team's experience, a communication system failure could last for an extended period of time. This will increase the possibility that a disturbance could occur during the communication failure.
2. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[4] Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.

The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[5]

Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

[44] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

[55] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 5	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 5	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Question 5	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	

Question 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 5	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes

Question 5	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 5	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	

Question 5	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 5	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	

Question 5	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 5	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Question 5	
Texas RE noticed the term “Overcurrent Element Pick-up Tolerance” still exists in Attachment 1 Figure A. Is this the SDT’s intention?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This terminology is consistent with the IEEE C37.17-2012 standard.	

Question 6

6. ***Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.***

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
I do not agree with application of this standard. Protection should be set up and coordinated for individual installs not by generitc percentages above MVA nameplates. Setting criteria should not be enforced by NERC unless NERC is willing to take responsibility for any equipment damage from settings being set to high.	
Likes 0	
Dislikes 0	
Response	
Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 6	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Question 6	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 6	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	

Question 6	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 6	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	

Question 6	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement is not necessary, and (2) 36 months where equipment removal or replacement is necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
The 36 months may not be long enough to replace the relays depending on the number of relays that have been identified for replacement. Suggest a change to 60 months, or "prorated" (The implementation period will be different based on the number of protection units that have been identified for replacement).	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
This does not allow for time needed to make any changes based on the new revision. Altering the calculations and re-reviewing current changes that have been made in accordance with PRC-025-1 will take time. Any non-compliant relays found due to the new revision may	

Question 7	
cause a delay in our ability to comply. We would request that more time be given to allow for proper implemenation of this new revision.	
Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Depending on the date that version 2 would eventually be approved, it is possible that that the version 2 enforcement date, for those assets explicitly in scope under version 1, could actually be earlier than the existing version 1 enforcement date. AEP recommends that the version 2 enforcement date should have the exact same enforcement date as in version 1 for those assets already explicitly in scope under version 1. As an example, the table below shows what would happen if the effective date for version 2 of PRC-025 were to be June 1 of 2018. As shown in the table provided, the version two enforcement dates for assets already explicitly in scope under version one, both for assets where no removal or replacement is necessary *and* for assets requiring removal or replacement, would be sooner that their corresponding enforecement dates under version one.

Requirement

Effective Date

Enforcement Date

PRC-025-1 R1 (No removal or replacement necessary)

Question 7	
10/01/14 10/01/19 PRC-025-**2** R1 Assets Already Explictly in Scope (No removal or replacement necessary) 06/01/18 06/01/19 PRC-025-1 R1 (Requires removal or replacement) 10/01/14 10/01/21 PRC-025-**2** R1 Assets Already Explictly in Scope (Requires removal or replacement) 06/01/18 05/31/21 AEP has chosen to vote negative on the proposed draft of PRC-025-2, driven by our concerns related to the proposed implementation plan.	
Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No

Question 7	
Document Name	
Comment	
The Implementation Plan should not require taking a special outage for PRC-025, and should therefore allow at least five years to make relay settings changes, and seven years to install new devices.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The Implementation Period should align with the existing Implementation Period of PRC-025-1 because that is what utilities have been working toward.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No

Question 7	
Document Name	
Comment	
As currently written, it appears the implementation plan can actually shorten the current timeframes to become compliant with PRC-025. If PRC-025-2 was approved and became effective prior to 10/1/18, entities would have less time to comply with the 2 scenarios under "Load-responsive protective relays subject to the standard" in the implementation plans. Currently entities have until 10/1/19 to comply when they will be making a setting change to meet the setting criteria and 10/1/21 to comply when they will be removing/replacing the relay to meet the setting criteria. Tri-State recommends adding language similar to the commonly used "shall become effective on the later of XXXX or the first day of the XX calendar quarter". That would prevent entities from losing time they might have already planned on having to become complaint with PRC-025-1. Additionally, can the SDT explain why they changed the timeframes (from 60 and 84 months to 12 and 36 months respectively) under "Load-responsive protective relays subject to the standard" but not the ones under "Load-responsive protective relays which become applicable to the standard" provided in the implementation plans.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Implementation Period should align with the existing Implementation Period of PRC-025-1 because that is what utilities have been working toward.	

Question 7	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
The Implementation Plan should not require taking a special outage for PRC-025, and should therefore allow at least five years to make relay settings changes, and seven years to install new devices.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA does not agree that a 12-month implementation period is sufficient for changes to relay settings that now may be required due to the new applicability of the 50 (instantaneous overcurrent) element in PRC-025-2 Draft 1. The original PRC-025-1 implementation plan allowed 5 years from approval to implement settings changes. This 5-year period was sufficient for implementing new relay settings,	

Question 7	
even for nuclear units which are tied to refueling outage schedules. TVA has seven nuclear units. Some other entities have even more. It is unreasonable to expect nuclear units to schedule additional outages that could be required within the proposed 1-year implementation period, just to perform relay settings changes.	
Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No

Question 7	
Document Name	
Comment	
The current standard's implementation plan states that the entity must be compliant by October 2019, or by October 2021 for the removal or replacement of applicable relays. The proposed implementation plan only identifies the retirement of the previous standard and does not provide a transition period between revisions. We propose incorporating a clause that begins the compliance period no earlier than October 2019, and no earlier than October 2021 for the removal or replacement of applicable relays.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Unless the SDT clarifies that the PRC-025 applicability section refers only to PRC-025 relays on 1) substation Bulk Electric System (BES) elements and 2) individual power producing resource relays at the BES generators, and that all collector system protective relays are excluded, the first implementation of PRC-025-1 was not clear and entities will need 60 months to staff and build systems to support zero-defect compliance monitoring and change management.	
Likes 0	
Dislikes 0	
Response	

Question 7	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
It would be beneficial for maintenance requirement to align with PRC-005 maintenance requirement since time between scheduled outages for generation units can be as long as 36 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.	
Likes 0	

Question 7	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG recommends changing the implementation plan since there is no correlation between the number of the relays requiring replacement and the arbitrary implementation period. We suggest the implementation period to be a function of the number of relays involved. Alternate graded approach is also possible i.e. 25, 50, 75 & 100% corresponding to 5 years.	
Likes 0	
Dislikes 0	
Response	

Question 7	
Thank you for your comment. The drafting team does not want to mandate the approach to the implementation. The Implementation Plan allows a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Question 7	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Question 7	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	

Question 7	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	

Question 7	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Question 7	
Answer	
Document Name	
Comment	
The proposed Implementation Plan is consistent with the timelines for compliance with PRC-025-1. Texas RE suggests the SDT clarifies that entities making a determination that replacement or removal is necessary, triggering the 36-month compliance window, should document those conclusions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team sees that as administrative and the responsibility of the entity to be able to demonstrate its compliance with the standard.	

Question 8	
8. *Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.*	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Stating that this is a severe VSL and high VRF is way more severe than the actual risk for not being in compliance with PRC-025-2 especially for asynchronous generators. If the settings and studies are done correctly there is no risk of false tripping even if the pickups are not as high as the requirements in this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The VRF of High is consistent with the application of settings on load-responsive protective relays in PRC-023 – Transmission Relay Loadability and was approved by industry and regulatory authorities. Not setting load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment is a risk to reliability. The single Severe VSL is due to the requirement being binary (i.e., pass/fail). The NERC guidelines for writing VSLs require the greatest category of VSL to be used for binary conditions.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Question 8	
Reclamation recommends there is a need for high/moderate/low VSLs based on the number of relays impacted by the standard. Reclamation recommends a VSL similar to that for PRC-005-6 R3 and R4. Reclamation recommends the following VSLs: Requirement Number - R1 Lower VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on fewer than 5% of its load-responsive protective relays. Moderate VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 5% to less than 10% of its load-responsive protective relays. High VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 10% to less than 15% of its load-responsive protective relays. Severe VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 15% or more of its load-responsive protective relays.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While the drafting team understands the approach, the performance of Requirement R1 is to set each load-responsive protective relay according to Table 1; therefore, the VSL does not lend itself to a gradated VSL.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe a performance-based criteria could be established for the Violation Severity Levels for this standard, similar to what is present for NERC Reliability Standard PRC-005-6. In that standard, the severity is based on a specific percentage of Components the applicable	

Question 8	
entity failed to maintain in accordance with minimum maintenance activities and maximum maintenance intervals. We recommend using the same criteria for this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While the drafting team understands the approach, the performance of Requirement R1 is to set each load-responsive protective relay according to Table 1; therefore, the VSL does not lend itself to a gradated VSL.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 8	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes

Question 8	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 8	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes

Question 8	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 8	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	

Question 8	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 8	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Question 8	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 8	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 8	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	

Question 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 8	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Question 8	
Document Name	
Comment	
Texas RE recommends changing the “and” to an “or”. Additionally, Texas RE requests the SDT consider providing a justification of the “Long Term Planning” time horizon as it has a significant impact on Penalty calculations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting used the term “including” to eliminate confusion over the use of “or” or “and.” The Time Horizon of “Long-term Planning” is consistent with the NERC Time Horizons[6] use.	

[6] http://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Question 9	
9. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
These options, and other options, which use the phrase “gross MW reported to the Transmission Planner” needs clarity. That values are reported to the Transmission Planner annually. These values change somewhat, annually. Should Transmission Owners re-evalute that data and the settings derived from that data annually? I believe the spirit of PRC-025 is met with a one-time implmenetation based on this generator data. There should be no burden on Transmission Owners to re-evaluate this geneator data every year and re-calculate setitngs every year. Even if the Transmission Owner chooses to calculate settings on data more conservative than what is reported to the Transmission Planner, there should not be a requirement against annually chaning data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team notes that the MW value reported to the Transmission Planner is a minimum value for calculating the settings. Attachment 1 states the following “[i]f different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.” It is incumbent on the applicable entity to ensure compliance with the standard when reported values change.	
Donald Lock - Talen Generation, LLC - 5	

Question 9	
Answer	No
Document Name	
Comment	
Entities that took NERC at their word in performing calculations and (where necessary) making changes under PRC-025-1 should be “grandfathered” for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for the calculations under 14a, 15a, and 16a have not substantively changed as the voltage used in the calculation is the line nominal voltage. In the case of calculations under 14b, 15b, and 16b using simulation, the depressed voltage location was moved from the high-side of the generator step-up (GSU) transformer to the remote end of the line (i.e., at the transmission network) to account for the impedance of the generator lead line. Depending on line length and impedance, the simulation results would result in calculating an overly conservative setting had the simulation be performed from the remote end of the line. The drafting team believes “grandfathering” is not necessary as the simulation option use would not have been widespread. Also, through outreach of the drafting team, the revisions made will be providing entities setting alternatives where compliance was not previously feasible. Therefore, it is not expected that entities would have a need to perform new calculations due to the changes proposed in the standard.	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	
See comments and alternative approaches to meet the intent of the Standard in response to Question 2 above.	
Likes 0	

Question 9	
Dislikes 0	
Response	
Thank you for your comment. Please see the response in Question 2 above for Exelon.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Entities that performed calculations per NERC guidance and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.r	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for the calculations under 14a, 15a, and 16a have not substantively changed as the voltage used in the calculation is the line nominal voltage. In the case of calculations under 14b, 15b, and 16b using simulation, the depressed voltage location was moved from the high-side of the generator step-up (GSU) transformer to the remote end of the line (i.e., at the transmission network) to account for the impedance of the generator lead line. Depending on line length and impedance, the simulation results would result in calculating an overly conservative setting had the simulation be performed from the remote end of the line. The drafting team believes “grandfathering” is not necessary as the simulation option use would not have been widespread. Also, through outreach of the drafting team, the revisions made will be providing entities setting alternatives where compliance was not previously feasible. Therefore, it is not expected that entities would have a need to perform new calculations due to the changes proposed in the standard.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	

Question 9	
Comment	
Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources. The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[7] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

[7] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 9	
We believe the standard is too inclusive of all load-responsive protective relays. The applicability of this standard should be reflective of other PRC Standards, such as NERC Reliability Standard PRC-019-2, and based on the BES definition and gross nameplate ratings of generation Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Each Generator Owner, Transmission Owner, and Distribution Provider is required to apply settings on each load-responsive protective relay while maintaining reliable fault protection. Similarly, PRC-019 (*Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection*) requires entities to verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. This is to ensure voltage regulating system controls, (including in-service limiters and protection functions) avoid disconnecting the generator unnecessarily, and that applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Question 9	
Cost efficiency would be achieved by focusing on the correct impactful objectives, such as common-mode design issues, while excluding zero-defect compliance monitoring/change management for individual collector systems or individual dispersed power producing resources. For example, without an outside source to provide internal capability curves, Option 5 may be extremely labor intensive to develop and maintain to zero-defect. Zero-defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. Reclamation recommends the SDT modify the applicability section to concentrate on common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. This appropriately focuses compliance efforts on the measurable impacts of common-mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[8] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No

[8] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 9	
Document Name	
Comment	
Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources. The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[9] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

[9] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 9	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 9	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 9	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 9	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Question 9	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	

Question 9	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 9	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	

Question 9	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 9	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes

Question 9	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	

Question 9	
Likes 0	
Dislikes 0	
Response	

Question 10	
10. ***Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict here.***	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any state jurisdictional conflicts with the standard. The goal of the question is to reveal such conflicts through the applicable entities that have a working knowledge of the various regulatory functions, rules, orders, tariffs, rate schedules, legislative requirements, and agreements in their jurisdiction so c may inform the drafting team of any such conflicts.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends that the SDT check to see if the inclusion of collector systems could infringe on state jurisdictions.	
Likes 0	

Question 10	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any state jurisdictional conflicts with the standard. The goal of the question is to reveal such conflicts through the applicable entities that have a working knowledge of the various regulatory functions, rules, orders, tariffs, rate schedules, legislative requirements, and agreements in their jurisdiction so they may inform the drafting team of any such conflicts.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any state jurisdictional conflicts with the standard. The goal of the question is to reveal such conflicts through the applicable entities that have a working knowledge of the various regulatory functions, rules, orders, tariffs, rate schedules, legislative requirements, and agreements in their jurisdiction so they may inform the drafting team of any such conflicts.	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	No
Document Name	
Comment	

Question 10	
No from a technical point of view, but there might be some regional variances with the version approved by the Regie de l'Énergie du Québec.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is not aware of any conflicts with Régie de l'énergie - Gouvernement du Québec.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 10	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	

Question 10	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 10	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	No
Document Name	

Question 10	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 10	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	

Question 10	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 10	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Question 10	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Question 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	

Question 10	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No

Question 10	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 10	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
11. ***Are you aware of a need for a regional variance or business practice that should be considered with this project? If yes, please identify the need here.***	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE requests this question be included for each project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NERC developer for the project has forwarded the request to NERC Standards staff for consideration.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Question 11	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Likes 0	

Question 11	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No

Question 11	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 11	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	

Question 11	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	

Question 11	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	

Question 11	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	

Question 11	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	

Question 11	
Hydro-Québec TransÉnergie has proposed calculations and simulations for a particular configuration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team considered the approach presented to NPCC August 2016 and concluded that simulation was a more appropriate method for determining the generator response for a unit that is significantly reduced due to the impedance of the transmission line.	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
It would be beneficial for maintenance requirement to align with PRC-005 maintenance requirement since time between scheduled outages for generation units can be as long as 36 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	

Question 12	
12. ***If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:***	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	
I was not able to log my vote in SBS despite being in the ballot pool and attempting to vote affirmative before the ballot close time. Please contact me to ensure this issue is remedied.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. NERC staff responded outside of the drafting team meeting.	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
Applicability Section 4.1 references "3.2, Facilities." This appears to be a typographical error; consider correcting to reference "4.2 Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The numbering sequence has been corrected.	

Question 12	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
All settings should be based off load ability and equipment ratings like option 5b allows. Setting elements to arbitrary values called out in PRC-025 is not good sound engineering and poor practice for protecting electrical equipment. Settings should be based on IEEE standards and studies preformed by the professional licensed engineer developing the settings.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of the drafting team's work is to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[10] The approach to determining the settings for load-responsive protective relays based on studies demonstrating that generator output and nameplate gross MW value provided a method for determining setting criteria. This was vetted and approved by industry in version one.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	

[1010] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 12

Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.

For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 “protective elements” or devices (which can be more than relays) expected by the PRC-025 drafting team.

As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three “protective elements” or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more “protective elements” or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the “smart crowbar” example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.
5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.
6.

Question 12
In this 3,000 wind turbine example there are 21,300 “protective elements” to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn’t include the substation System Protection devices that we already consider at the substation. What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues? Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements. **Proposed Solution:** 1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators. Replace the proposed Applicability section 3.2.5 *3.2.5 Elements utilized in the aggregation of dispersed power producing resources.* With: **3.2.5** Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event. **3.2.6** Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5. 2. Request that the PRC-025 standards drafting team consider defining “Protective element” for PRC-025 means, “protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

Question 12	
3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as: **Collector System:** Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above. 4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of "Element" and "Facility" to separate plant issues from individual generator issues (thanks to Darnez for this item): **NERC Defined Element:** Any electrical device with terminals that may be connected to other electrical devices such as a generator, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **NERC Defined Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[11] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Response to Proposed Solutions:	

[11] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., "20 - 30 MVA and typically has 10 – 15 turbines per single radial"). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient. 2. The term "protective element" is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." 3. There is no need to define "Collector System" within the standard. The standard uses the currently defined term "Element" to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements. 4. The drafting team does not agree that the definitions of the terms "Element" and "Facility" need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Figure examples should be added to show examples of "elements utilized in the aggregation of dispersed power producing resources" for clarity as the BES definition excludes these elements from the BES.	
Likes 0	
Dislikes 0	
Response	
The SDT provided a new Figure 4 to clarify elements utilized in the aggregation of dispersed power producing resources (e.g., collector system, feeders).	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Question 12	
Answer	
Document Name	
Comment	

Reclamation recommends the SDT clarify the definition of Unit Auxiliary Transformer (UAT) in footnote 1 on page 3 of 112 of the standard to state that a Unit Auxiliary Transformer does not include excitation supply power potential transformers.

Reclamation recommends the SDT clarify what benefit is derived from zero-defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues.

Reclamation recommends the SDT clarify the definition of Unit Auxiliary Transformer (UAT) in footnote 1 on page 3 of 112 of the standard to state that, “a Unit Auxiliary Transformer does not include excitation supply power potential transformers.”

For clarity, Reclamation recommends the SDT state the PRC-025 “protective elements” or devices (which can be more than relays) expected to be in scope. Reclamation recommends the SDT evaluate the impact of PRC-025 in terms of the number of PRC-025 devices, similar to the impact of PRC-005. All of these items (and potentially more, based on the recent NERC Lesson Learned, “Loss of Wind Turbines due to Transient Voltage Disturbances on the Bulk Transmission System”) would have to be tracked for zero defects, such as perfect settings and perfect knowledge of changes. This could result in an entity’s PRC-025 program being the same or greater size and workload as its PRC-005-6 program.

Following are some possible solutions to help focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solutions:

1. Reclamation recommends that the drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more and the loss of individual collectors or individual generators.

Reclamation recommends replacing the proposed Applicability section 3.2.5

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

Question 12
with: **3.2.5** Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event. **3.2.6** Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified in 3.2.5. 2. Reclamation recommends that the drafting team consider defining "protective element" as, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system." A protective element excludes fuses. 3. Reclamation recommends that the drafting team consider adding a NERC Glossary defined term of "Dispersed Power Producing Resource Collector System" such as: **Collector System:** Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above. 4. Reclamation recommends that the drafting team consider modifying the existing NERC Glossary definitions of "Element" and "Facility" to separate plant issues from individual generator issues as follows: **Element:** Any electrical device with terminals that may be connected to other electrical devices such as *an individual generator, an individual dispersed power producing resource*, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a *generating plant or aggregate dispersed power producing plant*, a shunt compensator, transformer, etc.)

Likes 0	
Dislikes 0	

Response
Thank you for your comment.

Question 12	
The drafting team notes that the Applicability section for unit auxiliary transformer (UAT) clearly does not include the excitation transformer. Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[12] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Response to Proposed Solutions: 1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., “20 - 30 MVA and typically has 10 – 15 turbines per single radial”). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient. 2. The term “protective element” is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.” 3. There is no need to define “Collector System” within the standard. The standard uses the currently defined term “Element” to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements. 4. The drafting team does not agree that the definitions of the terms “Element” and “Facility” need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	

[12] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
Document Name	
Comment	
1. Section 4.1 identifies functional entities that are applicable to this standard. These entities apply load-responsive protective relays at the terminal ends of the Elements identified in Section 3.2, Facilities. However, we believe the applicability of these Facilities are listed under Section 4.2. We observe this inconsistency throughout the standard. 2. This project continues to run independent of the current implementation plan identified for NERC Reliability Standard PRC-024-1. Although the phased-in implementation of this standard is still on-going, it very probable that a registered entity has already developed a complete compliance program that addresses the current version of this standard. We simply ask the SDT to acknowledge this possibility. 3. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. The drafting team corrected the section numbering error. 2. The drafting team acknowledges that entities may have taken any number of approaches to become compliant with the standard. The Implementation Plan allows a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	Project 2016-04 PRC-025-2Final.docx
Comment	
Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.	

Question 12
For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 “protective elements” or devices (which can be more than relays) expected by the PRC-025 drafting team. As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three “protective elements” or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more “protective elements” or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the “smart crowbar” example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes. Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program: 1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate. 2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate. 3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate. 4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate. 5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate. In this 3,000 wind turbine example there are 21,300 “protective elements” to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn’t include the substation System Protection devices that we already consider at the substation.

Question 12

What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues

Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solution:

1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

Replace the proposed Applicability section 3.2.5

3.2.5 Elements utilized in the aggregation of dispersed power producing resources

With:

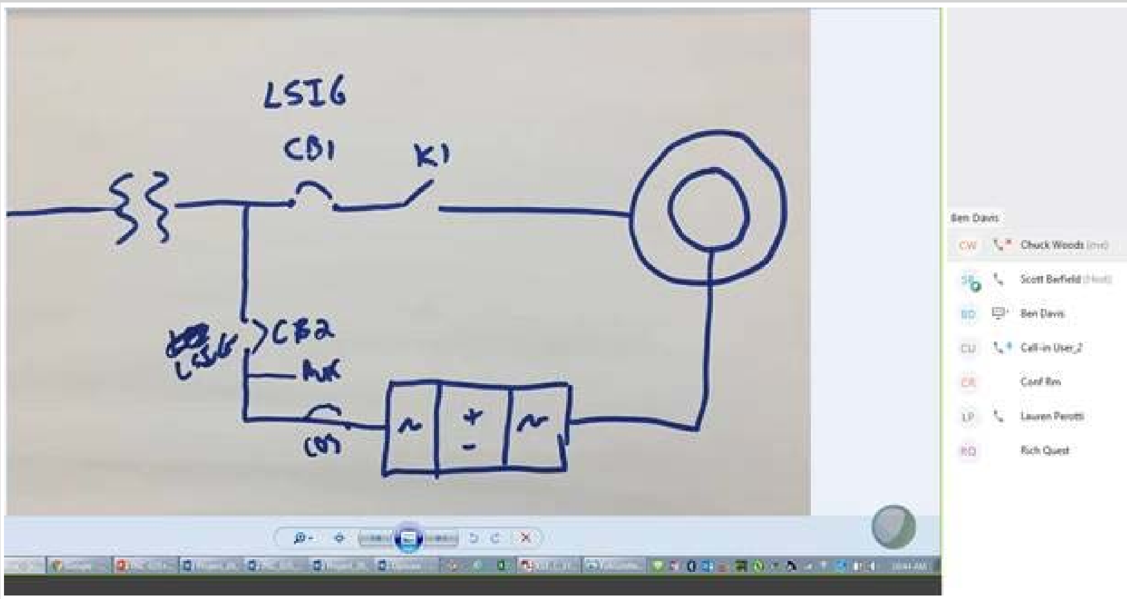
3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining “Protective element” for PRC-025 means, “protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as:

Collector System: Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

Question 12	
4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of “Element” and “Facility” to separate plant issues from individual generator issues (thanks to Darnez for this item): **NERC Defined Element:** Any electrical device with terminals that may be connected to other electrical devices such as a generator, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **NERC Defined Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.) Please see attached document for diagram.	
	
Likes 0	
Dislikes 0	
Response	

Question 12	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[13] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Response to Proposed Solutions: 1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., “20 - 30 MVA and typically has 10 – 15 turbines per single radial”). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient. 2. The term “protective element” is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.” 3. There is no need to define “Collector System” within the standard. The standard uses the currently defined term “Element” to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements. 4. The drafting team does not agree that the definitions of the terms “Element” and “Facility” need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	
Document Name	

[13] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
Comment	
Several times the term "Real Power output" is defined in the proposed standard as "100% of the aggregate generation gross MW capability reported to the Transmission Planner." TVA believes that it can be difficult to determine what is meant by "capability reported to the transmission planner," and would like to see the standard clarify on which reporting mechanism or process this generation capability is normally expected to be based. A Transmission Planner can have multiple capabilities reported for one unit. For example, a MOD-025 capability verified by test or operational data, versus a planned capability that reflects a modification to be implemented in the near future.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The "gross MW capability reported to the Transmission Planner" is based upon NERC Reliability Standard MOD-025-2. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	
Table 1 seems to explicity require specific reach settings and does not address how to comply with the standard if using a quad element and not a mho element, even though a quad element is uncommon in generator relays. Additionally, there is not a clear path in the standard regarding load encroachment blocking. Load encroachment blocking is mentioned in the PRC-025-1 Application Guideline and the the NERC SPCS report "Considerations for Power Plant and Transmission System Protection Coordination" but is absent in the standard.	
Likes 0	

Question 12	
Dislikes 0	
Response	
Thank you for your comment. The drafting team notes that the standard addresses what is required and not how to accomplish the setting criteria. Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
In Table 1, Relay Type column, for Options 14, 15, 16, 17, 18, and 19, consider changing "…installed on the high-side of the GSU transformer and [on the] remote end of the line" to something like "…installed on the high-side of the GSU transformer and/or [on the] remote end of the line" or "…installed on the high-side of the GSU transformer, including [on the] remote end of the line." A simple 'and' suggests that relaying at both locations may be required.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team clarified the relay location by moving the information from the "Relay Type" column of Table 1 to the "Application" column for each of the applicable Options.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	

Question 12	
The SDT should modify the applicability section to concentrate on common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded as in PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[14] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE inquires about the use of the Application Guideline as there are several changes in the works with regards to attached documents. Texas RE's understanding is that any guidance as to how to comply with a standard will go through the Implementation Guidance	

[14] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
process. Any technical basis will be in a Technical Rationale document. How does the Application Guidance in PRC-025-2 fit in with the new schematic? In addition, Texas RE requests the technical reason that the GO might provide a base setting on capability that is higher than what is reported to the Transmission planner, as noted in Attachment 1. Texas RE also noticed the following grammatical issues/typos: • The header still has "-1" throughout Standard. • Applicability section 4.1 references "3.2, Facilities" which does not exist. It should reference "4.2, Facilities". • Facility section 4.2.4 has two sentences that conflict. The first sentence says "used exclusively to export"; the second sentence says "may also supply". If an element is used exclusively for something, that precludes it from also including something else. • The Compliance Monitoring Process section is incorrectly numbered as "8" (and subparts 8.1, 8.2, etc.).	
Likes 0	
Dislikes 0	
Response	
GTB – Check with NERC staff The drafting team notes that the MW value reported to the Transmission Planner is a minimum value for calculating the settings. Attachment 1 states the following "[i]f different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner." It is incumbent on the applicable entity to ensure compliance with the standard when reported values change. Thank you for your comments. • The header has been corrected. • The Applicability section numbering has been corrected. • The Applicability has been revised to add obviously missing words and improving clarity.	

Question 12	
• The Compliance section numbering has been corrected.	
Ruth Miller - Exelon - 5	
Answer	
Document Name	
Comment	
None. Thank You	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
As written, NERC Reliability Standard PRC-025-2 Generator Relay Loadability does not account for equipment limitations of the generator step-up transformer or generation lead line that would not allow an entity to set it's protective relays to the level as specified within the standard. The SDT needs add additional option for these application that is similar to option 5B.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Equipment limitations for other applications in Table 1 have not been identified by industry.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	

Question 12	
Answer	
Document Name	
Comment	
Tri-State would like to point out that there seems to be an error in "Section 4.1 Functional Entities" where the sub bullets are referencing section "3.2, Facilities." That should be "4.2, Facilities."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The number error has been corrected.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG recommend that instead of “relay location” to use “relay associated instrument transformers (PT’s/CT’s) location”. Clarification are recommended for the cases where the protective device settings are not achievable due to additional possible constrictions related to the supply path associated equipment. This can be achieved by defining the “resource” in Option 5b.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard specifies the location of the relays based on the zone of protection of the Element. Option 5b allows closer matching of the resource output and should address the overloading concerns of the low voltage feeder facilities and other associated equipment in the path.	

Question 12	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	
Document Name	
Comment	
Please clarify if switch-onto-fault is meant to be included in Attachment 1: Relay Settings. Exclusion #1 states, “Any relay elements that are in service only during start up.” Is switch-onto-fault included as an element that is only service during start up? PRC-023 specifically addresses switch-onto-fault in Attachment A as applicable to the standard; addressing switch-on-to-fault in PRC-025 would provide consistency and clarity between the two similar standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Switch-on-to-fault (SOTF) schemes are not included because they are only enabled for a brief period following the re-energizing of a line.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	
Document Name	
Comment	
Section 4.1 (Functional Entities) references the Elements listed in Section 3.2 (Facilities); however, Section 3.2 (Facilities) does not exist within the PRC-025-2 – Generator Relay Loadability proposed standard document. Section 4.1 (Functional Entities) should instead be updated to reference the Elements listed in Section 4.2 (Facilities).	
Likes 0	
Dislikes 0	

Question 12	
Response	
Thank you for your comment. The error has been corrected.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy recommends the drafting team consider adding another option (perhaps 13c) that would address the high side UAT overcurrent settings under this standard. We suggest adding: *“Where there is only one UAT low side protective device that is set at a minimum 135% of the UAT nameplate or 135% or greater than load operating at .85 per unit voltage, the UAT high side protective device must be set equal to or coordinate with the low side protective device.”* The issue this would address is the prudent protection settings and compliance of the high side overcurrent with the standard. In some instances, the high side overcurrent is coordinating with the low side overcurrent. Currently, there is nothing that is addressing the low side. We feel that this is a technical flaw in the standard, which should be addressed.	

Question 12	
Also, there are some instances where some BES UAT's with high side fuses will operate at less that 150% UAT ratings. Based on these instances, we feel that fuses should be considered as an addition to the relay type category. We suggest that the drafting team consider making the changes referenced above to correct the technical errors, or remove references to the UAT in the standard altogether.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of the drafting team's work is to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[15] The drafting team is not authorized to make changes to the unit auxiliary transformer settings. Correct, the low-side protection was not addressed in the version 1 standard. This issue was studied by the version one drafting team following the approval of version 1. It was found that the individual plant feeder loadability was not a reliability issue. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016."[16] Fuses are not subject to the standard. Only load-responsive protective relays.	
Tom Haire - Rutherford EMC - 3	
Answer	
Document Name	
Comment	

[15] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

[16] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf

Question 12	
Section 4.2.5 should have a minimum threshhold. Section 4.1 should reference 4.2 not 3.2	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Applicability 4.2.5 already has a threshold based on the resource meeting the I4 inclusion of the Bulk Electric System (BES) definition as defined by the Glossary of Terms Used in NERC Reliability Standards. The incorrect applicability references and numbering have been corrected.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP has chosen to vote negative on the proposed draft of PRC-025-2, driven by our concerns related to the proposed implementation plan (detailed in our response to Q7). AEP recommends a more appropriate per unit voltage level of 0.85 per unit, rather than 1.0 per unit, for options 13a, 13b, 17, and 18 within Table 1. In the Applicability section, all references to “3.2, Facilities” should instead be “**4**.2, Facilities.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response concerning the Implementation Plan in Question 7.	

Question 12
The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin. Options 17 and 18 are associated with asynchronous resources and use 1.0 per unit voltage because the current is limited based on the rating of the resource regardless of a lower voltage. The Applicability number error has been corrected.

Additional comments/information received from Russel Mountjoy – MRO NSRF

Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

   ☐ Yes

   ☒ No

   Comments: Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solare facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.

   Response:

   Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instanteous) as well as low voltage trip designations commonly

referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments: The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements" please add the word "PRC-025 relay" in front to clearly state that only "PRC-025 relays" are applicable, not control systems, not protective algorithms, and not fuses.

If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.

Response:

Thank you for your comment. The drafting team had already revised locations regarding "element" and "relay" to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard.

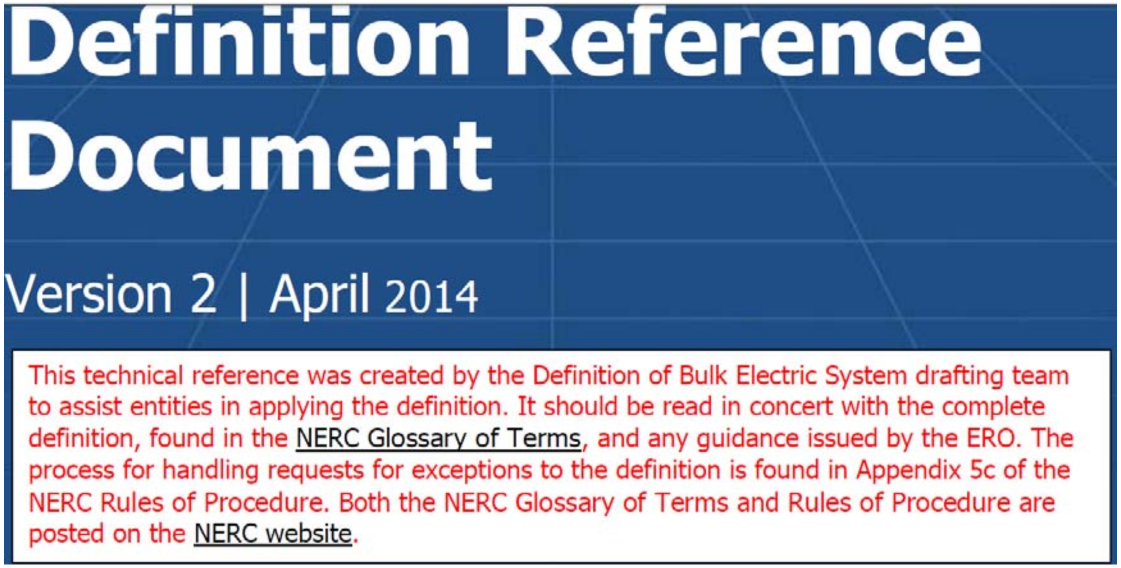
The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments: No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85.



Definition Reference Document

Version 2 | April 2014

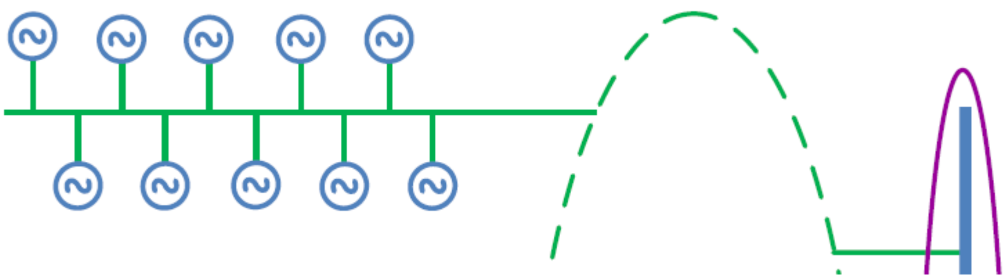
This technical reference was created by the Definition of Bulk Electric System drafting team to assist entities in applying the definition. It should be read in concert with the complete definition, found in the NERC Glossary of Terms, and any guidance issued by the ERO. The process for handling requests for exceptions to the definition is found in Appendix 5c of the NERC Rules of Procedure. Both the NERC Glossary of Terms and Rules of Procedure are posted on the NERC website.

Figure I4-2 depicts a dispersed generation site and substation design with unknown collector system configuration.

Typical dispersed generation site and substation design (single transformation of voltage level) with a gross aggregate nameplate rating of 80 MVA (Individual Generator Unit Rating: 2 MVA). By application of Inclusion I4 the dispersed power producing resources and the Elements from the point of aggregation to the common point connection are BES Elements.

Green indicates the portions of the Collector System that are not included in the BES.

Blue identifies the dispersed power producing resources and BES Elements between the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.



Link:

http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

Please state that Technical Guidance is for examples only, guidance isn’t enforceable and cannot alter the scope of compliance.

Response:

Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the “collector system configuration” is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator’s system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of “Element” (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition.

4. Do you agree that the proposed revisions in Table 1 for Options 14 thorugh 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

☒ Yes

☐ No

Comments:

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments:

The applicability section states that PRC-025 applies to relays. Removing "Pickup" suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing "Pickup". Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.

Response:

Thank you for your comment. The drafting team addressed the removal of "Pickup" from the standard as scoped in the SAR and agrees that "Settings Criteria" is a more appropriate term for the value. The use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to "not trip" based on the criteria in Table 1.

The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

☒ Yes

☐ No

Comments:

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement **is not** necessary, and (2) 36 months where equipment removal or replacement **is** necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

☐ Yes

☒ No

Comments: No. The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.

Response:

Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.

Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

☒ Yes

☐ No

Comments:

8. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

   ☐ Yes

   ☒ No

   Comments: Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources.

   The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6.

   This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.

   Response:

   Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance17 have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

9. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If **yes**, please identify the conflict here.

☐ Yes

☒ No

Comments: No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.

Response:

Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

10. Are you aware of a need for a regional variance or business practice that should be considered with this project? If **yes**, please identify the need here.

☐ Yes

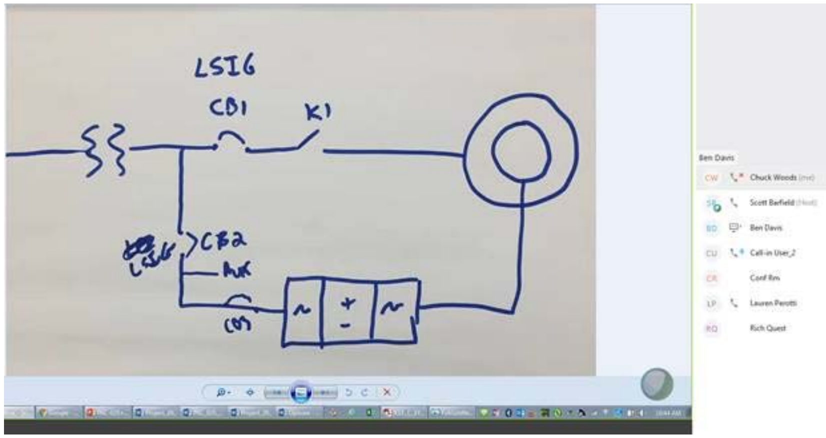
☒ No

Comments:

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

Comments:

Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.



For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 “protective elements” or devices (which can be more than relays) expected by the PRC-025 drafting team.

As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three “protective elements” or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more “protective elements” or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the “smart crowbar” example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.

5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.

   In this 3,000 wind turbine example there are 21,300 "protective elements" to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn't include the substation System Protection devices that we already consider at the substation.

   What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues?

   Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solution:

1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

   Replace the proposed Applicability section 3.2.5

   ~~*3.2.5 Elements utilized in the aggregation of dispersed power producing resources.*~~

   With:

   3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

   3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining "Protective element" for PRC-025 means, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as:

Collector System: Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of "Element" and "Facility" to separate plant issues from individual generator issues (thanks to Darnez for this item):

NERC Defined Element: Any electrical device with terminals that may be connected to other electrical devices such as ~~a generator~~, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Defined Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a ~~generator~~ generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)

Response:

Thank you for your comment.

The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance18 have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

---

[18] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Response to Proposed Solutions:

1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., "20 - 30 MVA and typically has 10 – 15 turbines per single radial"). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient.
2. The term "protective element" is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."
3. There is no need to define "Collector System" within the standard. The standard uses the currently defined term "Element" to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements.
4. The drafting team does not agree that the definitions of the terms "Element" and "Facility" need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

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.

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf).

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 Compliance Enforcement Authority (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 Generator Owner, Transmission Owner, and Distribution Provider 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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 Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, "Considerations for Power Plant and Transmission System Protection Coordination," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[7] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[8] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51)[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

[9] If the relay is installed on the high-side of the GSU transformer use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer use Option 18.
[11] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 7.

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>Setting Criteria</th></tr>
<tr><td rowspan="4">Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators</td><td rowspan="3">Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)</td><td>15a</td><td>0.85 per unit of the line nominal voltage at the relay location</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>15b</td><td>Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

[13] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) –connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[14] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[17] If the relay is installed on the generator-side of the GSU transformer use Option 12.

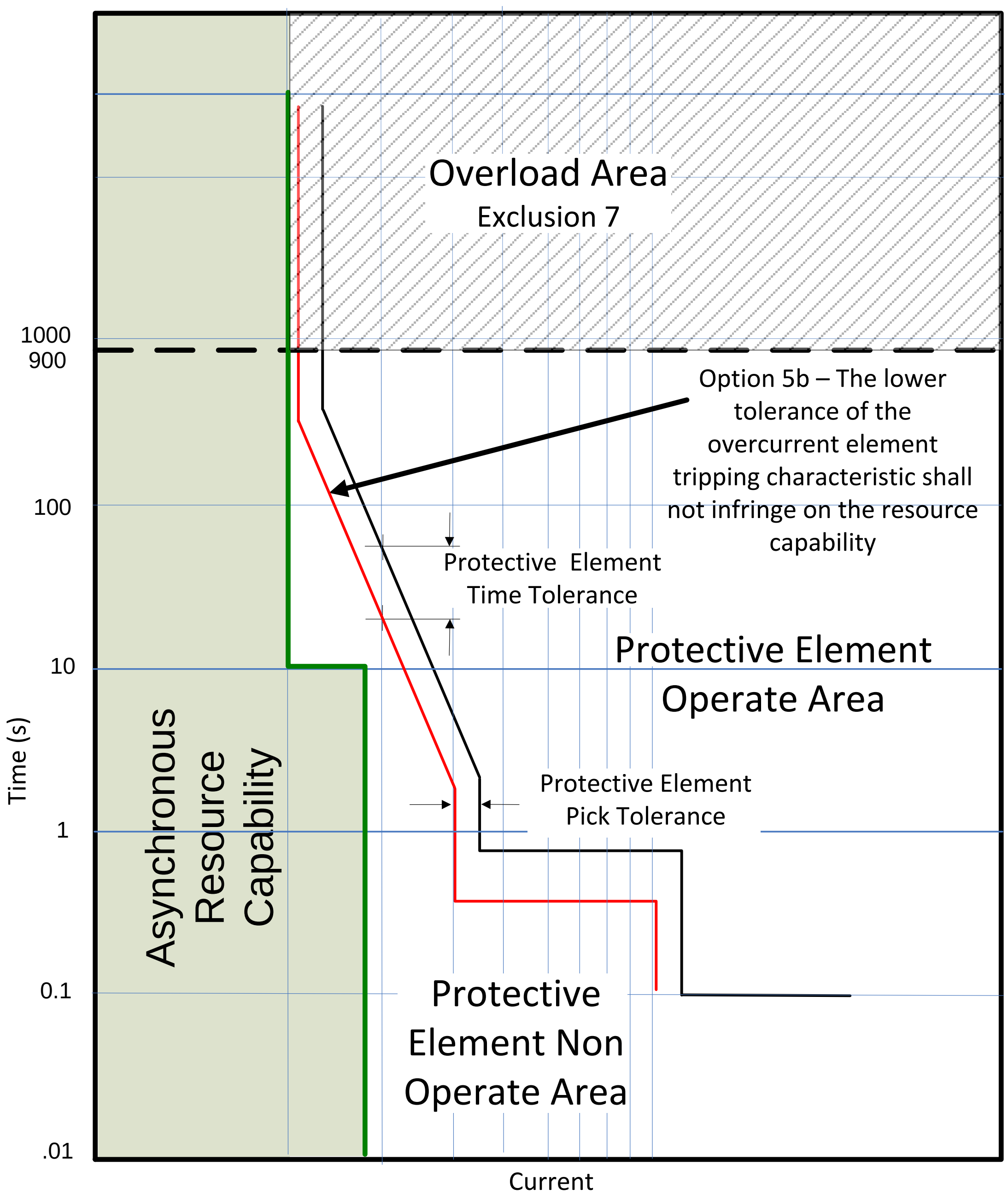


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

[18] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20 Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

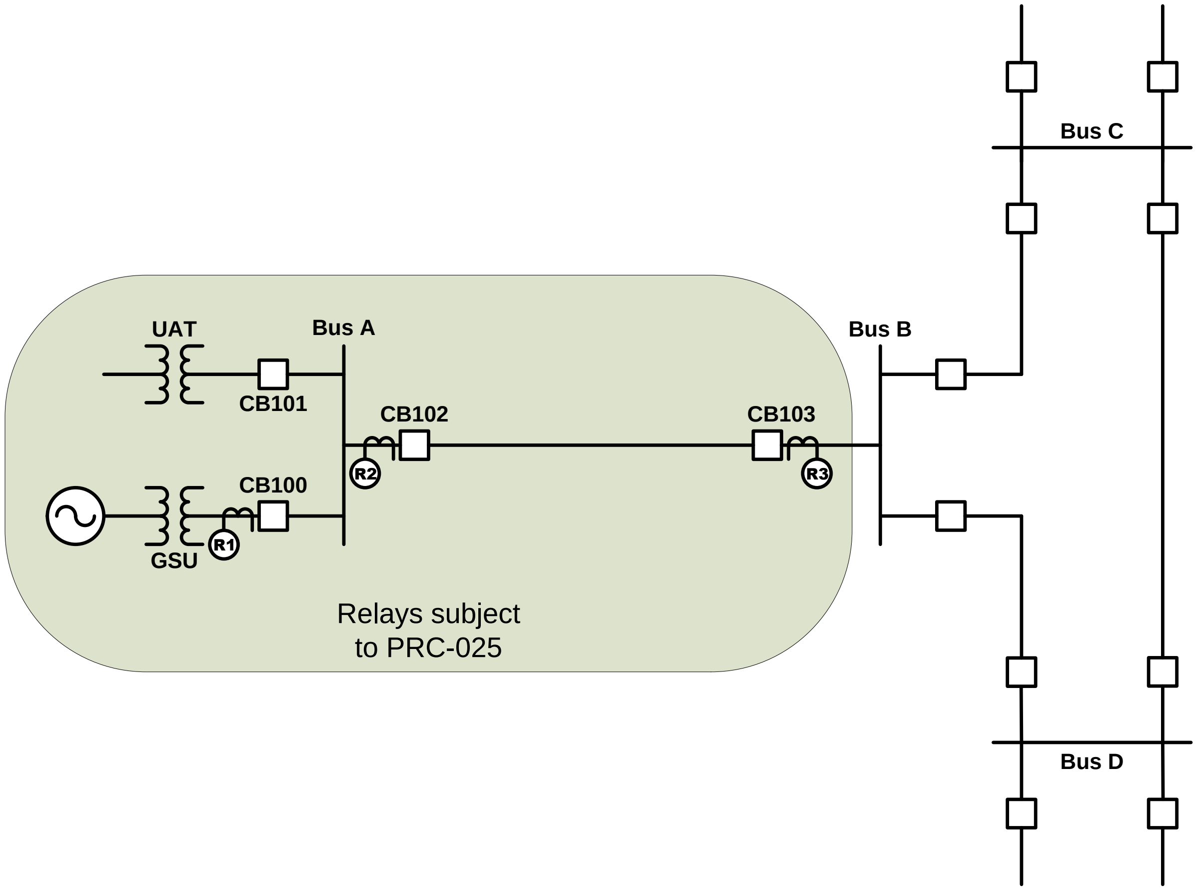


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

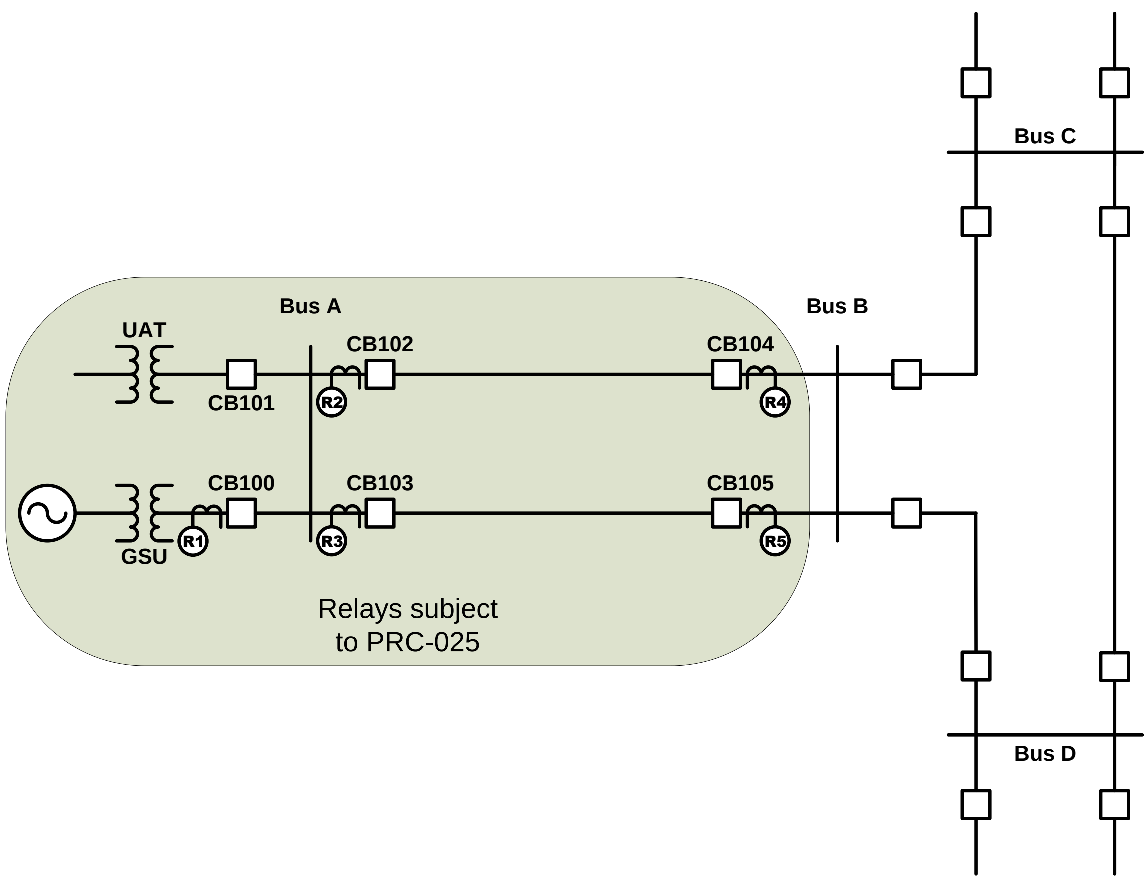


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

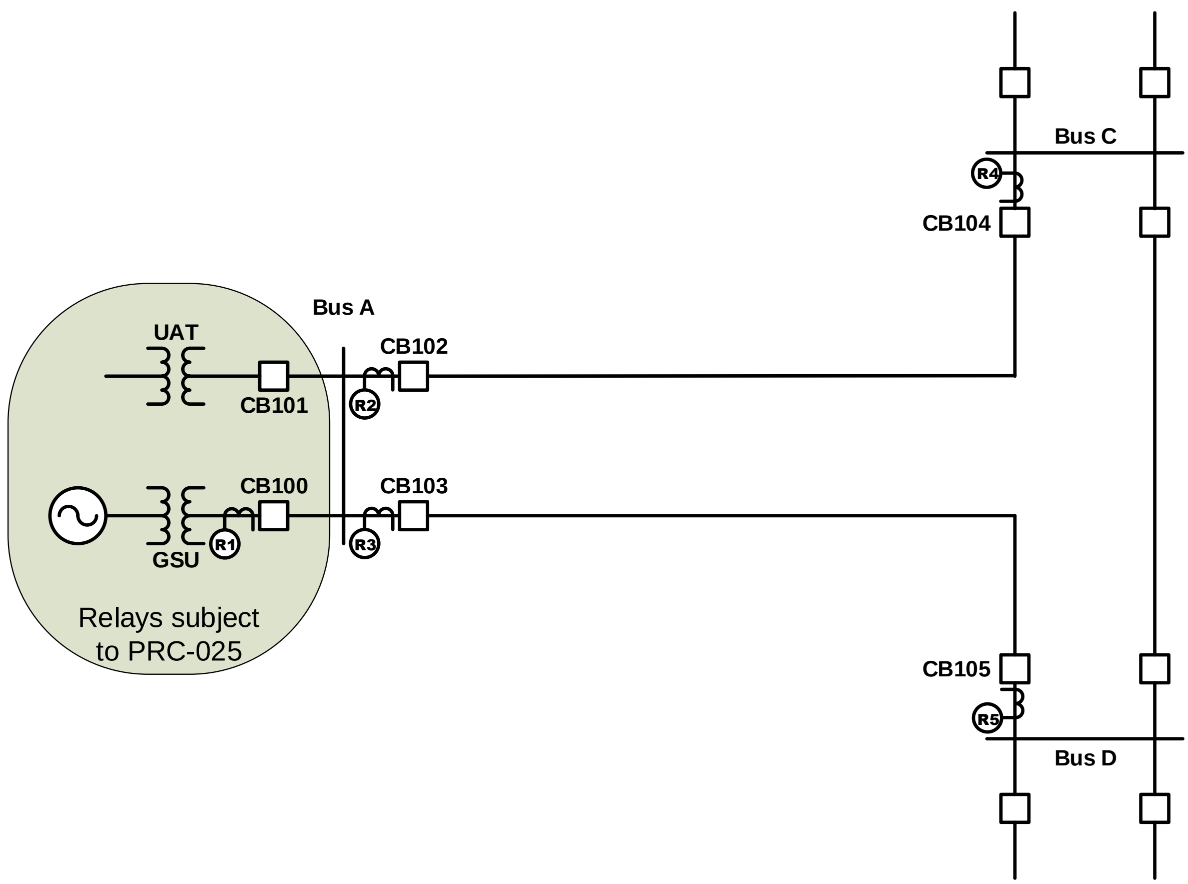


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

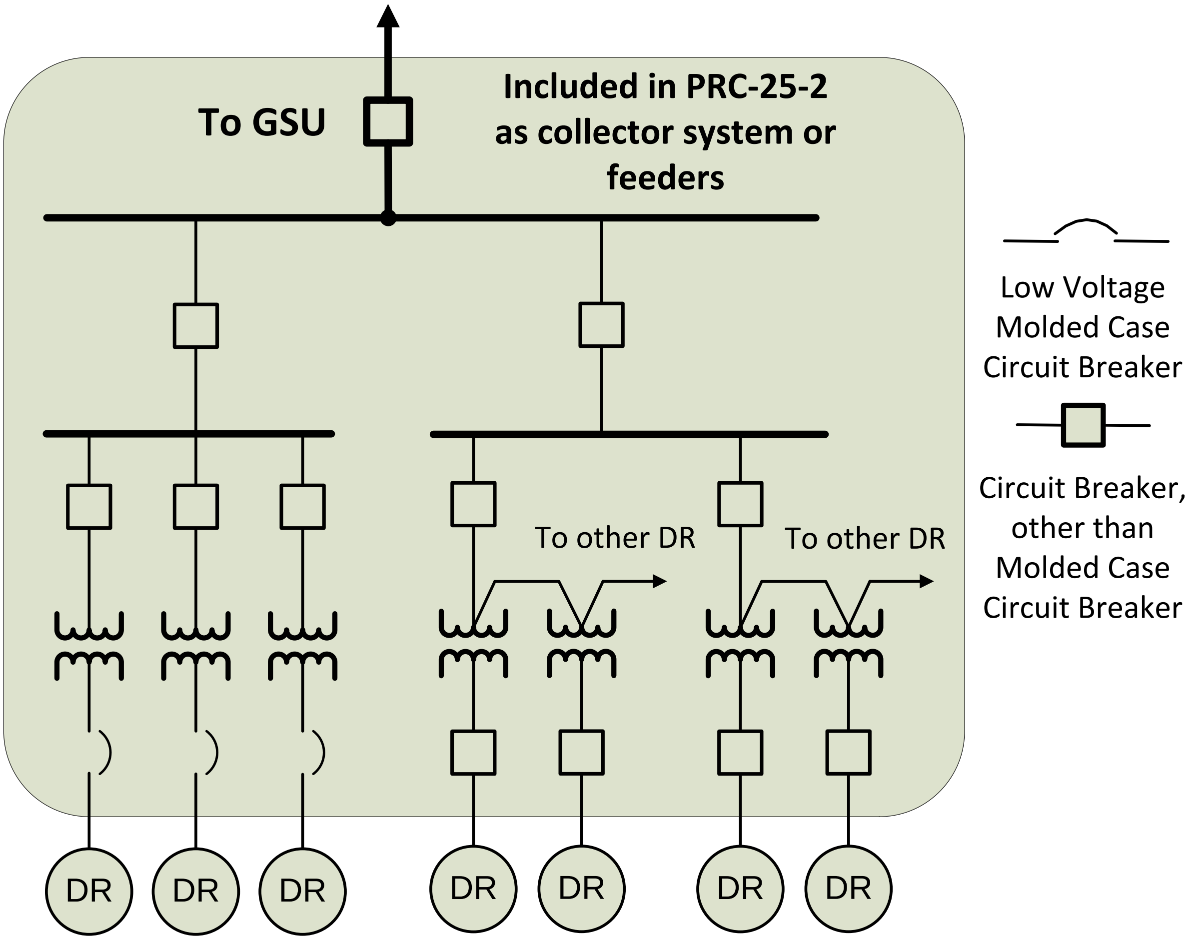


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column “Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

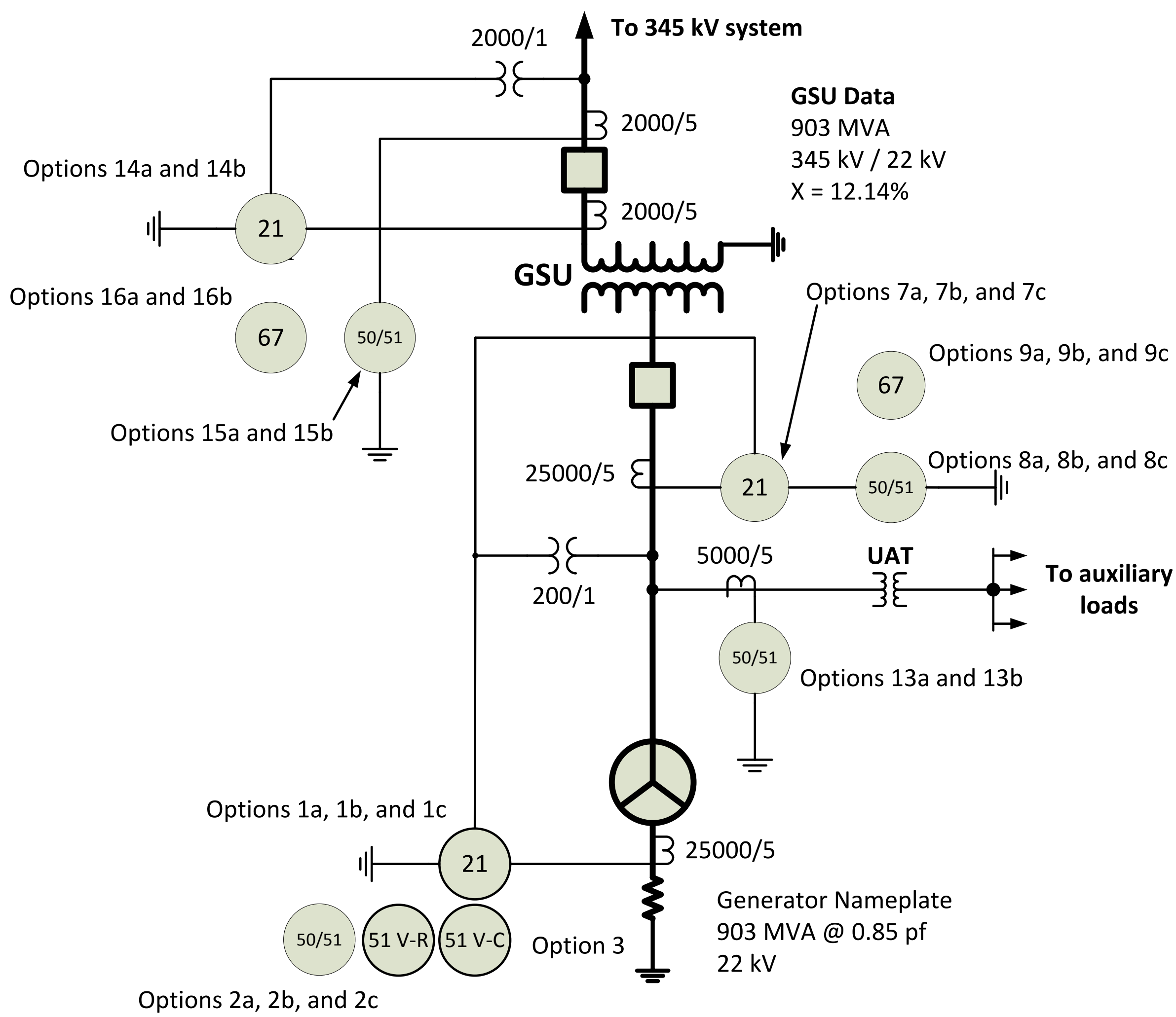


Figure 5: Relay Connection for corresponding synchronous options

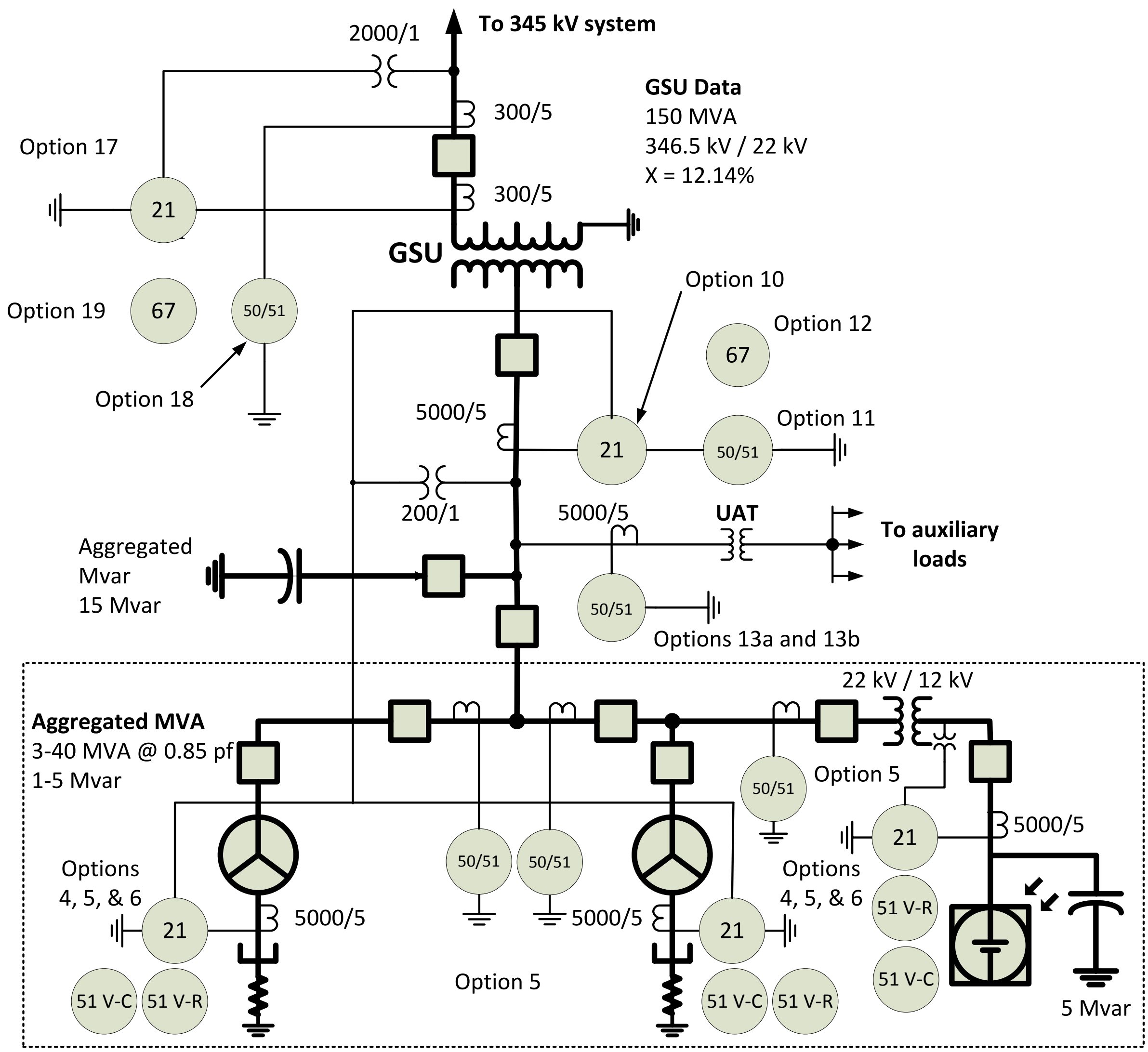


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

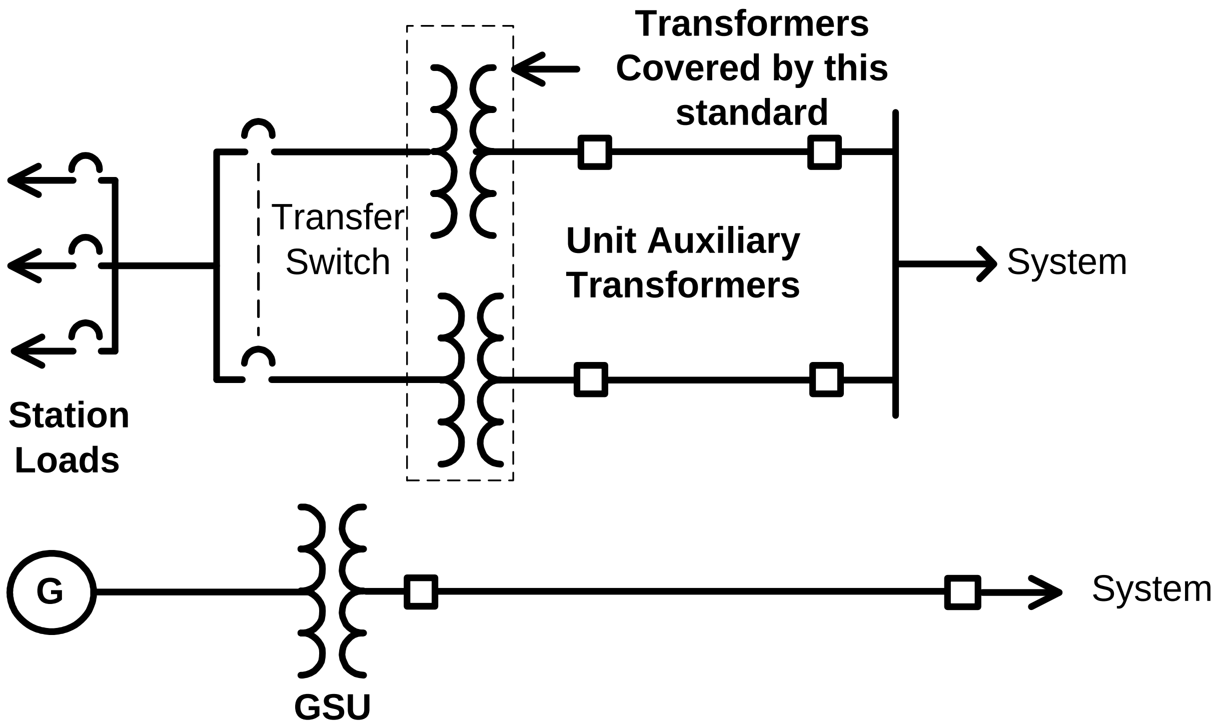


Figure 7: Auxiliary Power System (independent from generator)

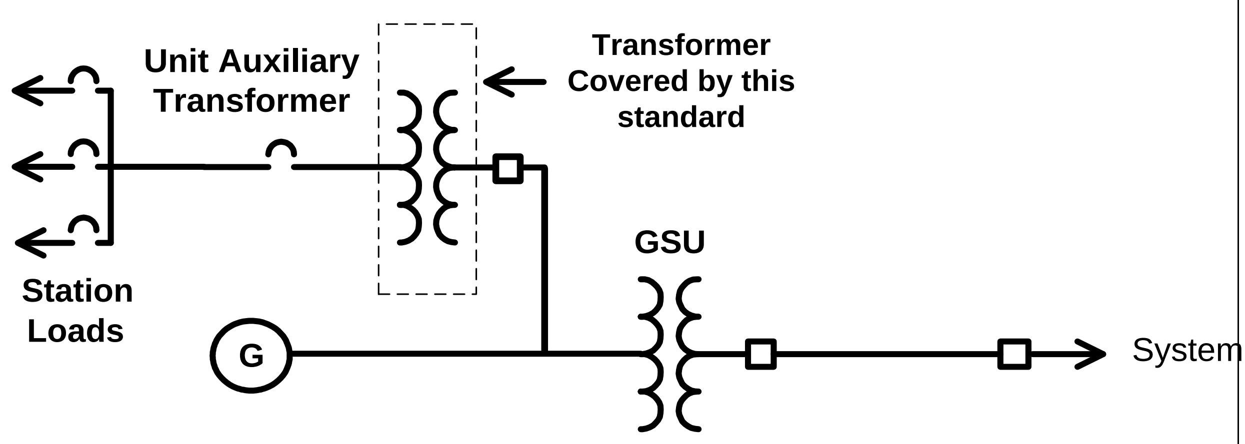


Figure 8: Typical auxiliary power system for generation units or plants

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the

transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\mathrm{sec}\ limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\mathrm{sec}\ limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\mathrm{sec}\ limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\mathrm{sec}\ limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

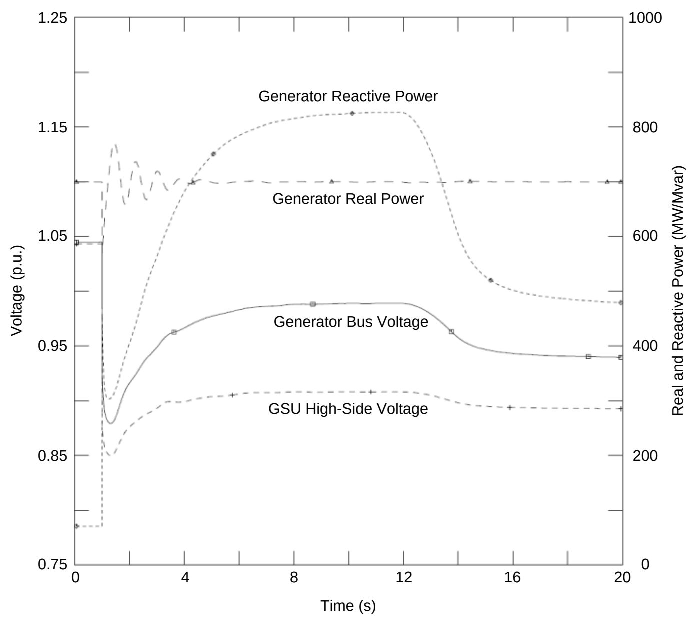
$$Z_{max} < \frac{7.74\,\Omega}{0.8965}$$

$$Z_{max} < \ 8.633\angle 85.0°\,\Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Option 2b

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8449 \pm 1.1546}{2}$$

$$\left|V_{low-side}\right| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = \left|V_{low-side}\right| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

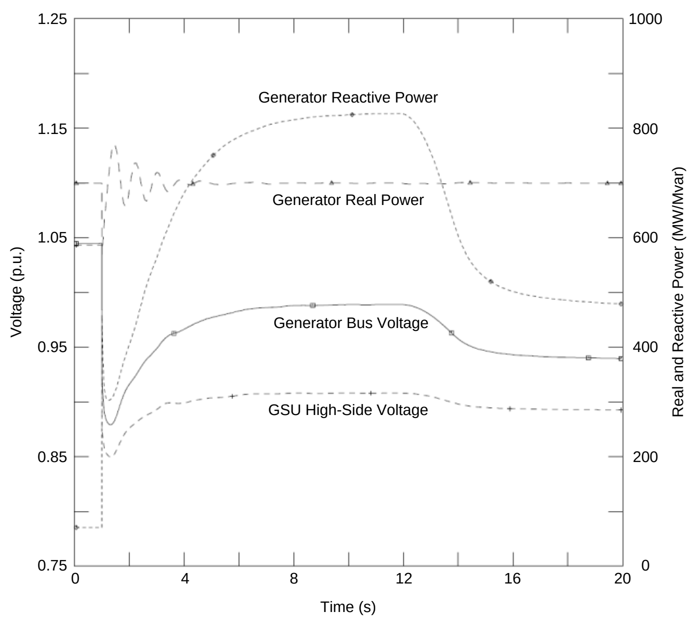
$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° \; A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \; MVA \; \times 0.85$$

$$P = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \; Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0 \; p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \; kV \times \left(\frac{22 \; kV}{346.5 \; kV}\right)$$

$$V_{gen} = 21.9 \; kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0 \; MW + j83.2 \; Mvar$$

$$S = 131.6\angle 39.2° \; MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$Q_{Synch} = 1.50 \times 767.6\ MW$

$Q_{Synch} = 1151.3\ MW$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \, \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \, \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0° \, \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7° \, A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \, MVA \times 0.85$$

$$P_{Asynch} = 102.0 \, MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \, Mvar + 5 \, Mvar + (3 \times 40 \, MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \, Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \, kV \times \left(\frac{22 \, kV}{346.5 \, kV}\right)$$

$$V_{gen} = 20.81 \, kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \, MW + j83.2 \, Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2° \, MVA$$

Primary current ($I_{pri-async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2° \, MVA}{1.73 \times 20.81 \, kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\text{sec}\,limit} > I_{sec} \times 100\%$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A \times 1.00$$

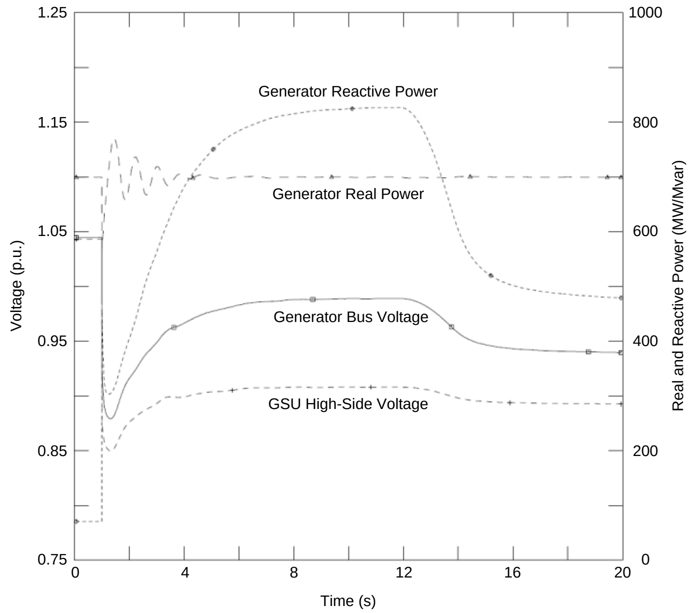
$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $Z_{\sec limit} = \frac{Z_{sec}}{130\%}$

Example Calculations: Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle -39.2° \ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \ MVA}{1.73 \times 13.8 \ kV}$$

$$I_{pri} = 2510.2 \ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \ \mathrm{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51 \ A \times 1.50$$

$$I_{\sec limit} > 3.77 \ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\mathrm{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\mathrm{sec}\,limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\mathrm{sec}\,limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\mathrm{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

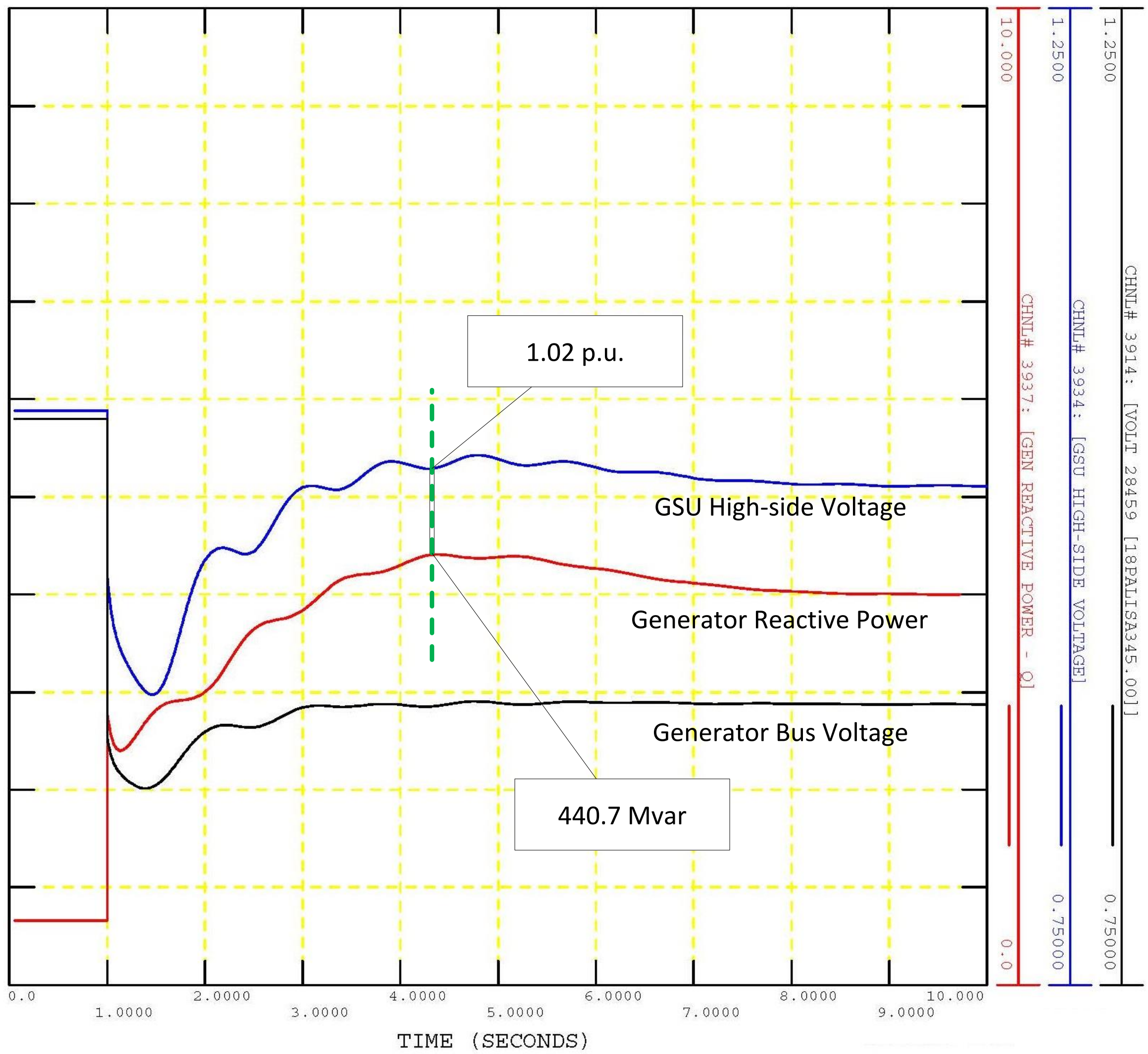
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (152) $S = P_{Synch\_reported} + jQ$

Example Calculations: Option 14b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle - 52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle - 52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle - 52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle - 52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = \ GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85\ p.u.\times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

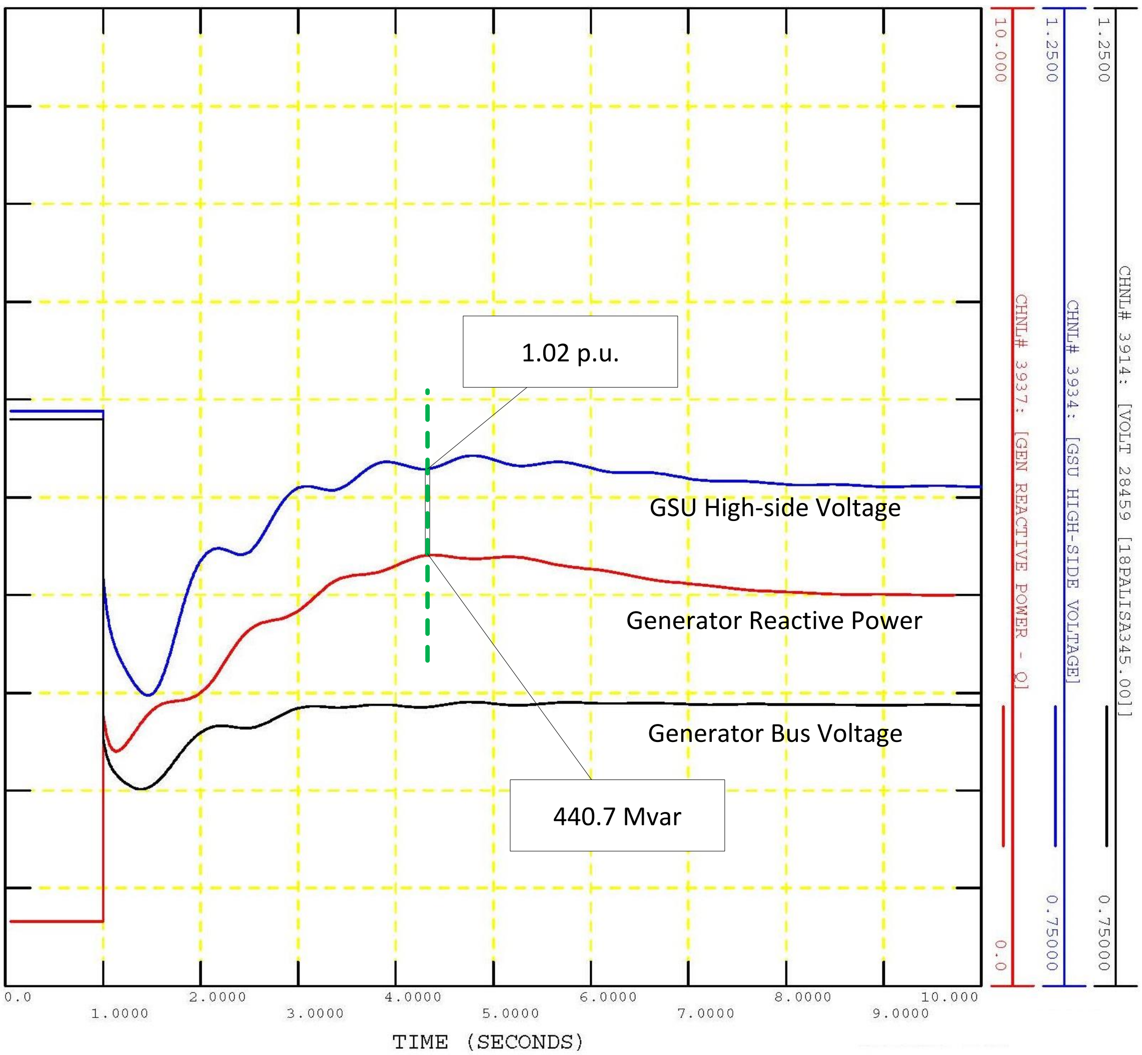
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

Example Calculations: Options 15b and 16b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 3.39\angle -32.2°\ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 3.39\angle -32.2°\ A \times 1.15$$

$$I_{\sec limit} > 3.90\angle -32.2°\ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

Eq. (175) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

Eq. (176) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $Z_{pri} = \dfrac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\,\Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\,\Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\,\Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\,\Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\,\Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\,\Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\,\Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\,\Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

Example Calculations: Options 18 and 19

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	~~September~~October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~, except that Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

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.

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf~~)~~).

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 Compliance Enforcement Authority (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 Generator Owner, Transmission Owner, and Distribution Provider 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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 Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, "Considerations for Power Plant and Transmission System Protection Coordination," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>Setting Criteria</th></tr>
<tr><td rowspan="6">Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources</td><td rowspan="5">Phase distance relay (e.g., 21) – directional toward the Transmission system</td><td>1a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>1b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>1c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and
(2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) ~~with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).~~See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer[7]~~	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

6 If the relay is installed on the high-side of the GSU transformer use Option 14.

~~7 If the relay is installed on the high-side of the GSU transformer use Option 14.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51) ~~– installed on generator-side of the GSU transformer[9]~~	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[8] If the relay is installed on the high-side of the GSU transformer use Option 15.

~~[9] If the relay is installed on the high-side of the GSU transformer use Option 15.~~

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Relays installed on generator-side[10] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer[11]~~	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

[10] If the relay is installed on the high-side of the GSU transformer use Option 16.

~~[11] If the relay is installed on the high-side of the GSU transformer use Option 16.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system~~ – installed on generator-side of the GSU transformer~~[12]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51) ~~– installed on generator-side of the GSU transformer~~[13]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system~~ – installed on generator-side of the GSU transformer~~[14]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

[12] If the relay is installed on the high-side of the GSU transformer use Option 17.
[13] If the relay is installed on the high-side of the GSU transformer use Option 18.
[14] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
A different application starts on the next page				
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip~~.~~	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s)	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[15] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	~~and on the remote end of line[16]~~	14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Relays installed on the high-side of the GSU transformer,[17] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		~~OR~~		

~~[16] If the relay is installed on the generator-side of the GSU transformer use Option 7.~~
[17] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer and remote end of the line~~ and/or phase time overcurrent relay (e.g., 51)~~– installed on the high-side of the GSU transformer and remote end of the line[18]~~	~~15b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~
	~~The same application continues on the next page with a different relay type~~			
~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~	~~Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-~~	~~16a~~	~~0.85 per unit of the line nominal voltage at the relay location~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor~~
		OR		

~~[18] If the relay is installed on the generator-side of the GSU transformer use Option 8.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
~~(Elements may also supply generating plant load.) –connected to synchronous generators~~	~~assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[19]~~	~~16b~~15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

~~[19] If the relay is installed on the generator-side of the GSU transformer use Option 9.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[20] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) –connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[20] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[21] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system~~– installed on the high-side of the GSU transformer and on the remote end of line[22]~~	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[21] If the relay is installed on the generator-side of the GSU transformer use Option 10.

~~[22] If the relay is installed on the generator-side of the GSU transformer use Option 10.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[23] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer and on the remote end of the line~~ and/or Phase time overcurrent relay (e.g., 51)~~ – installed on the high-side of the GSU transformer and on the remote end of the line[24]~~	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[23] If the relay is installed on the generator-side of the GSU transformer use Option 11.

~~[24] If the relay is installed on the generator-side of the GSU transformer use Option 11.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[25] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer and on the remote end of the line~~ and/or Phase directional time overcurrent relay (e.g., 67)~~ – installed on the high-side of the GSU transformer and on the remote end of the line[26]~~	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

[25] If the relay is installed on the generator-side of the GSU transformer use Option 12.

~~[26] If the relay is installed on the generator-side of the GSU transformer use Option 12.~~

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
End of Table 1				

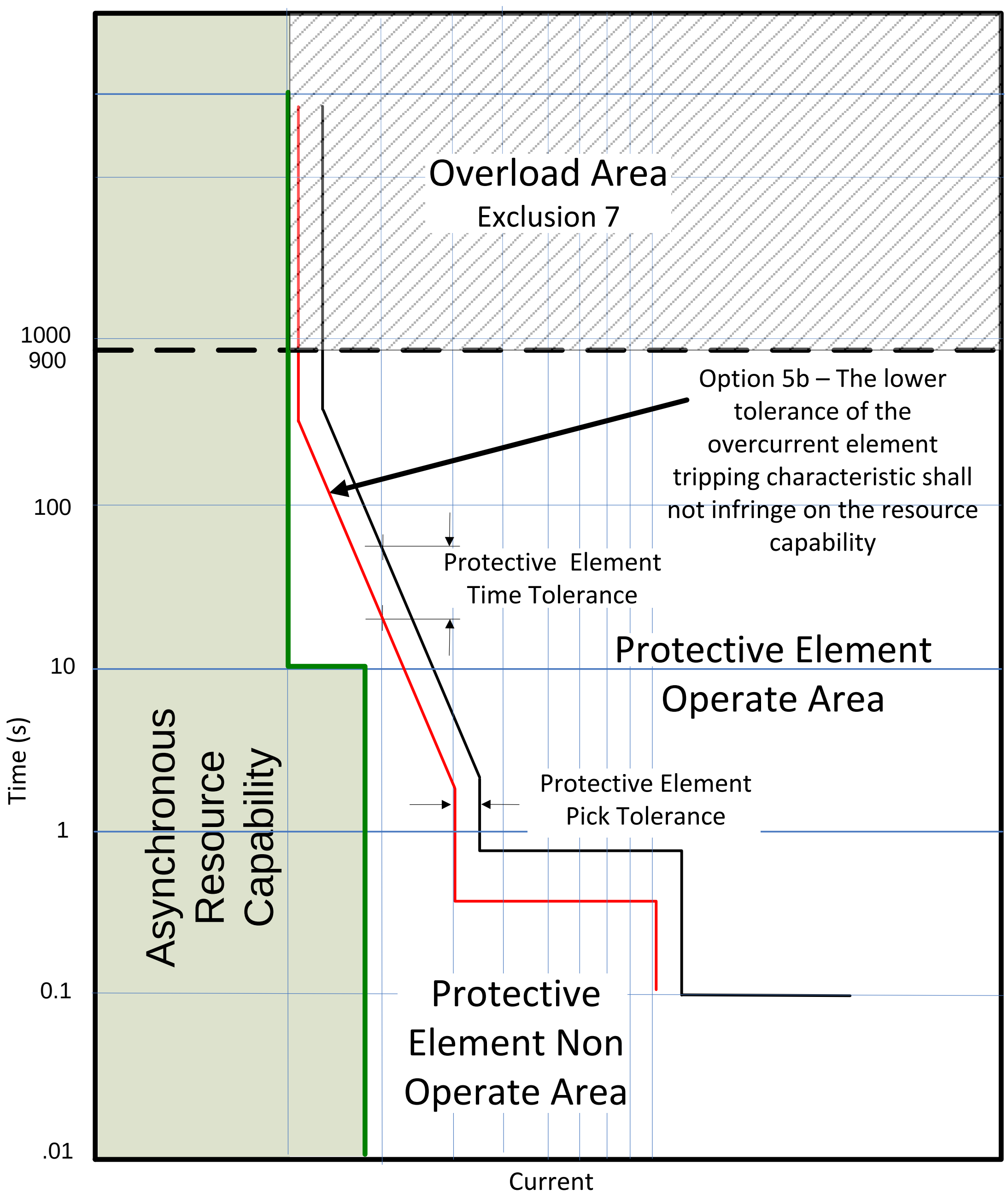


Figure A

~~.~~This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[27]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

[27] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

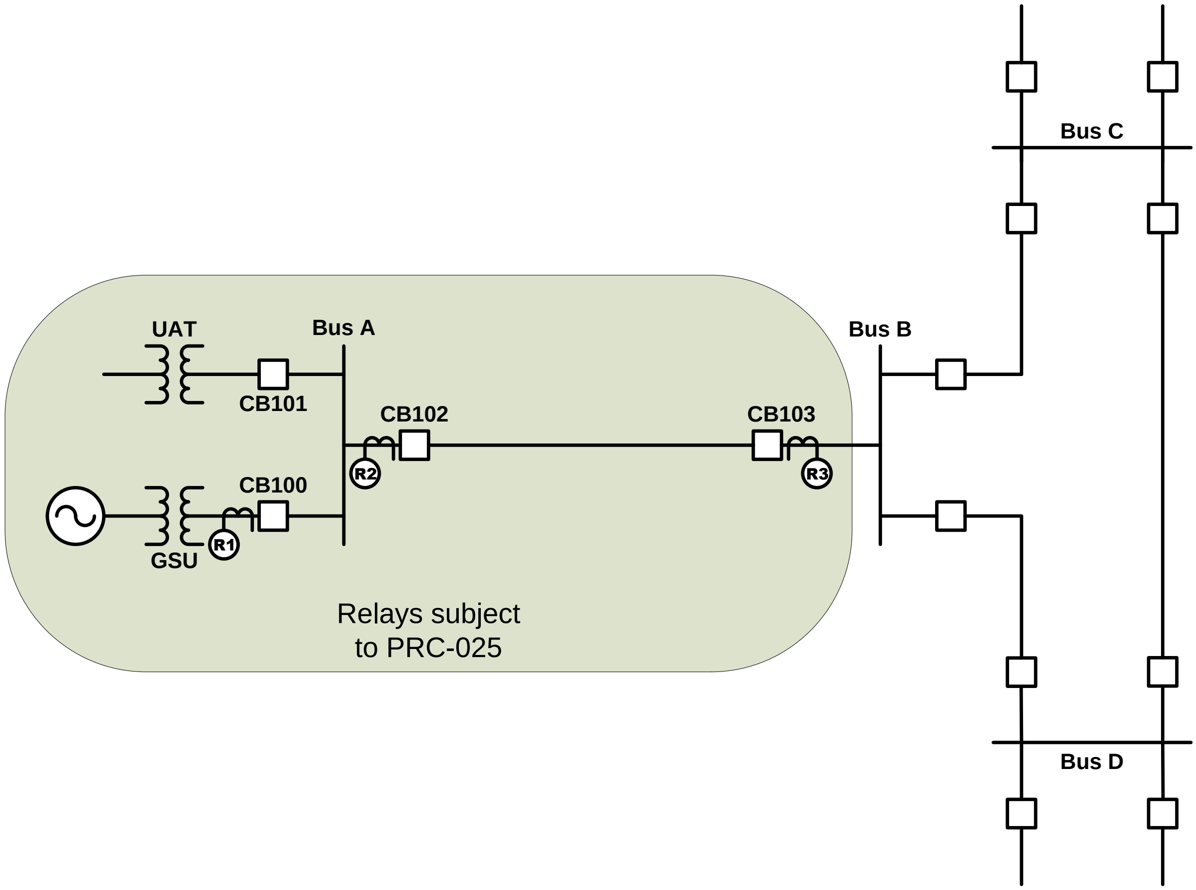


Figure 1~~.~~: Generation exported through a single radial line~~.~~

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

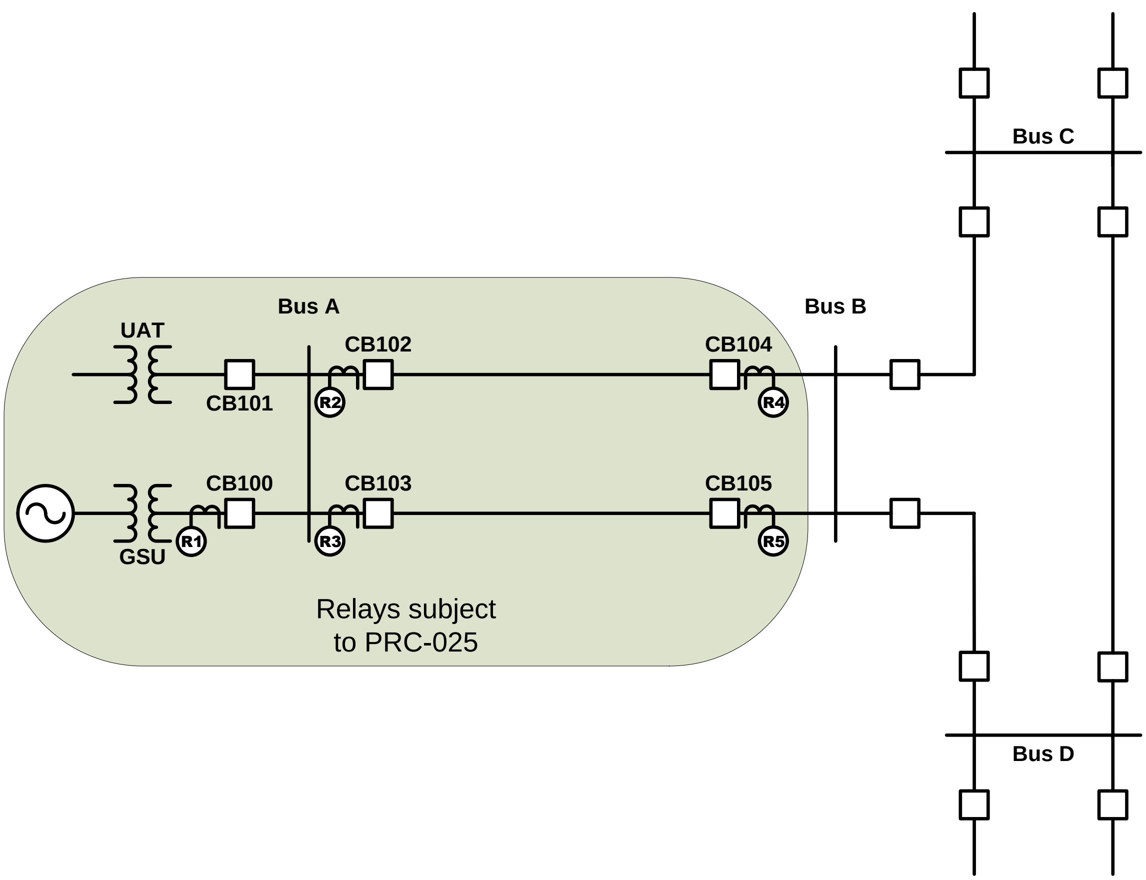


Figure 2~~.~~: Generation exported through multiple radial lines~~.~~

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

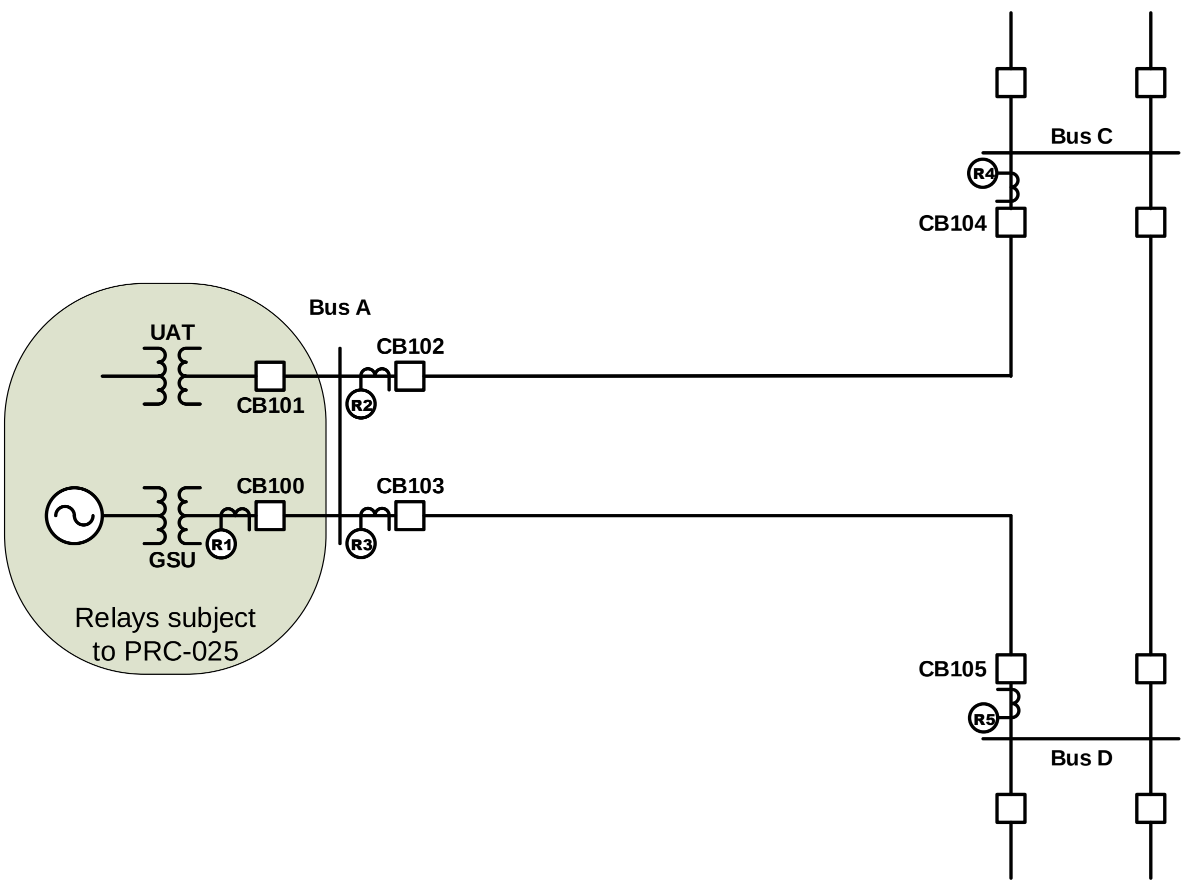


Figure 3~~.~~: Generation exported through a network~~.~~

~~Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.~~

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[28] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[28] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

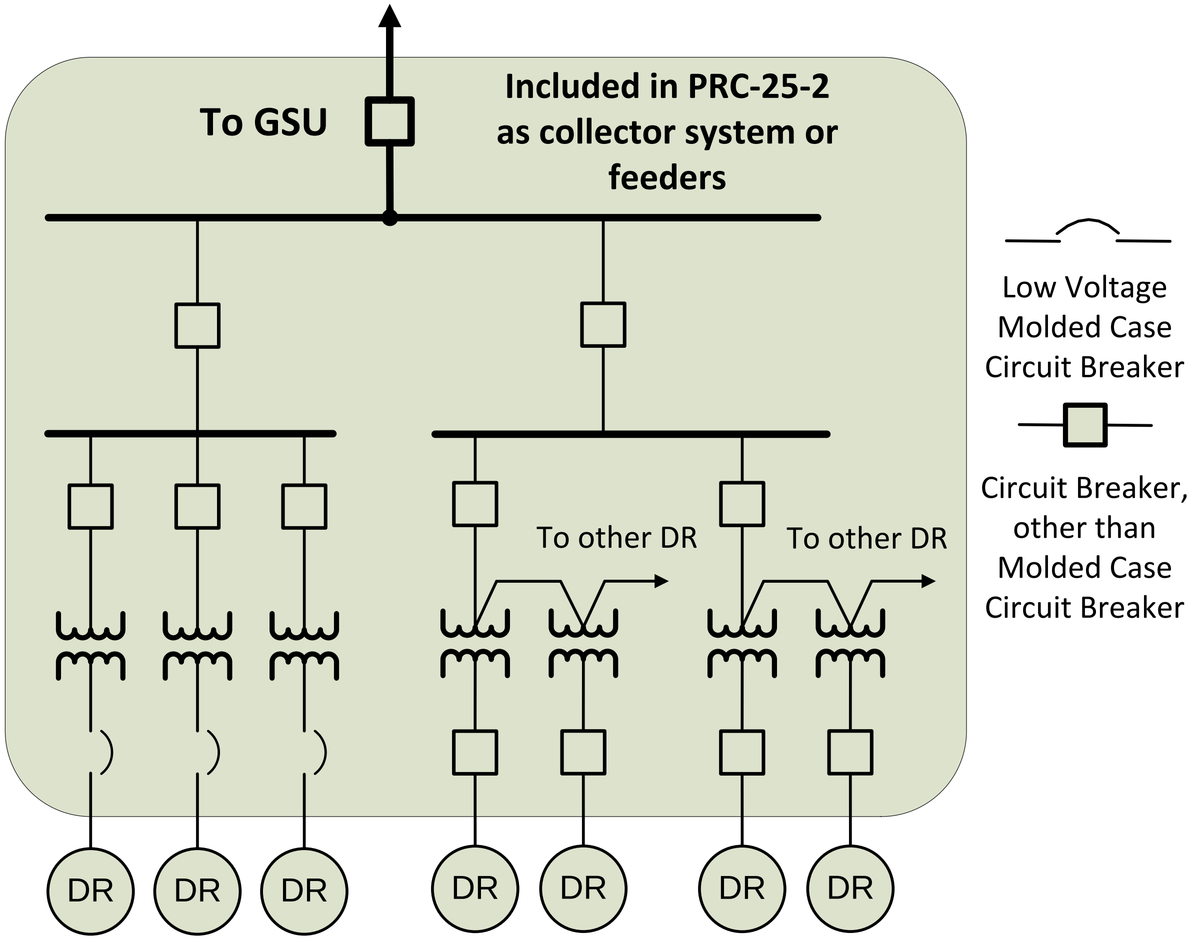


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure ~~5~~6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage ~~to be used~~at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of

Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options ~~differs~~differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options ~~differs~~differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures ~~4~~5 and ~~5~~6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

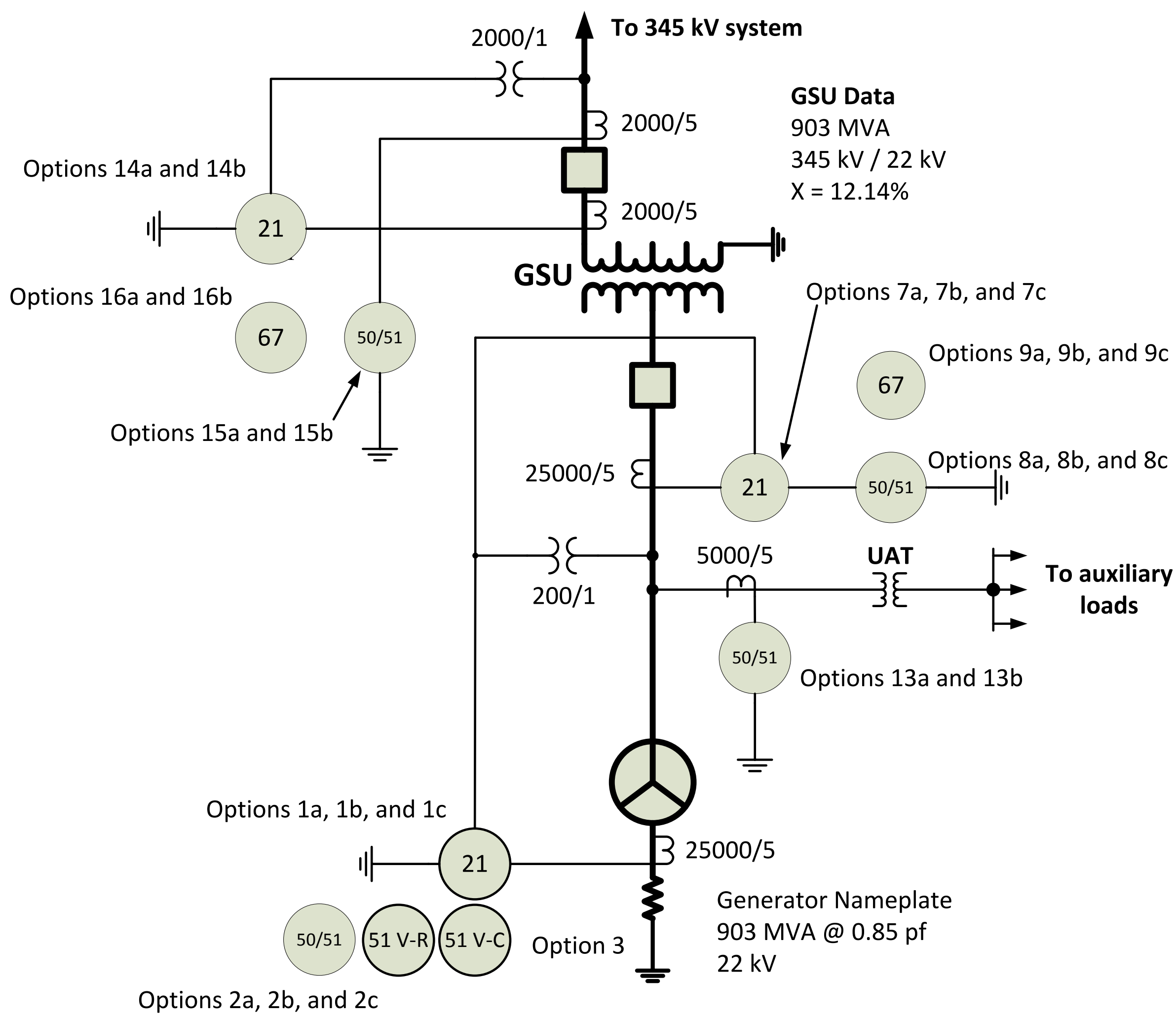


Figure ~~4.~~5: Relay Connection for corresponding synchronous options~~.~~

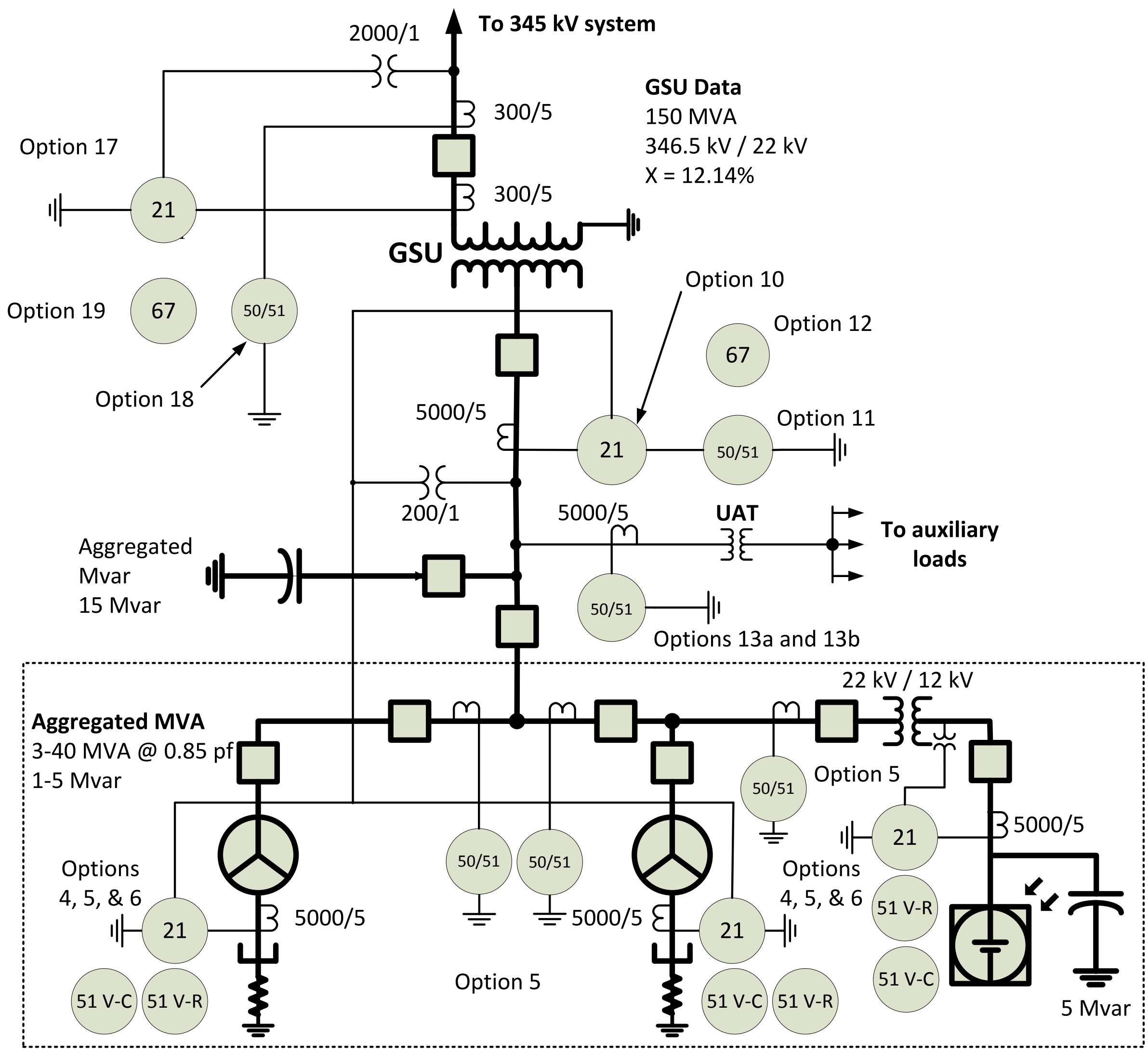


Figure ~~5.~~6: Relay Connection for corresponding asynchronous options including inverter-based installations~~.~~

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or ~~51) or~~51V-R – voltage-restrained ~~(e.g., 51V-R) which changes its sensitivity as a function of voltage (“voltage-restrained”).~~). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or ~~51) or~~51V-R – voltage-restrained~~ (e.g., 51V-R) which changes its sensitivity as a function of voltage ("voltage-restrained").~~). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability ~~with worst case documented tolerances applied to the setting.~~(including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback~~. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant~~.

Refer to the Figures ~~6~~7 and ~~7~~8 below for example configurations:

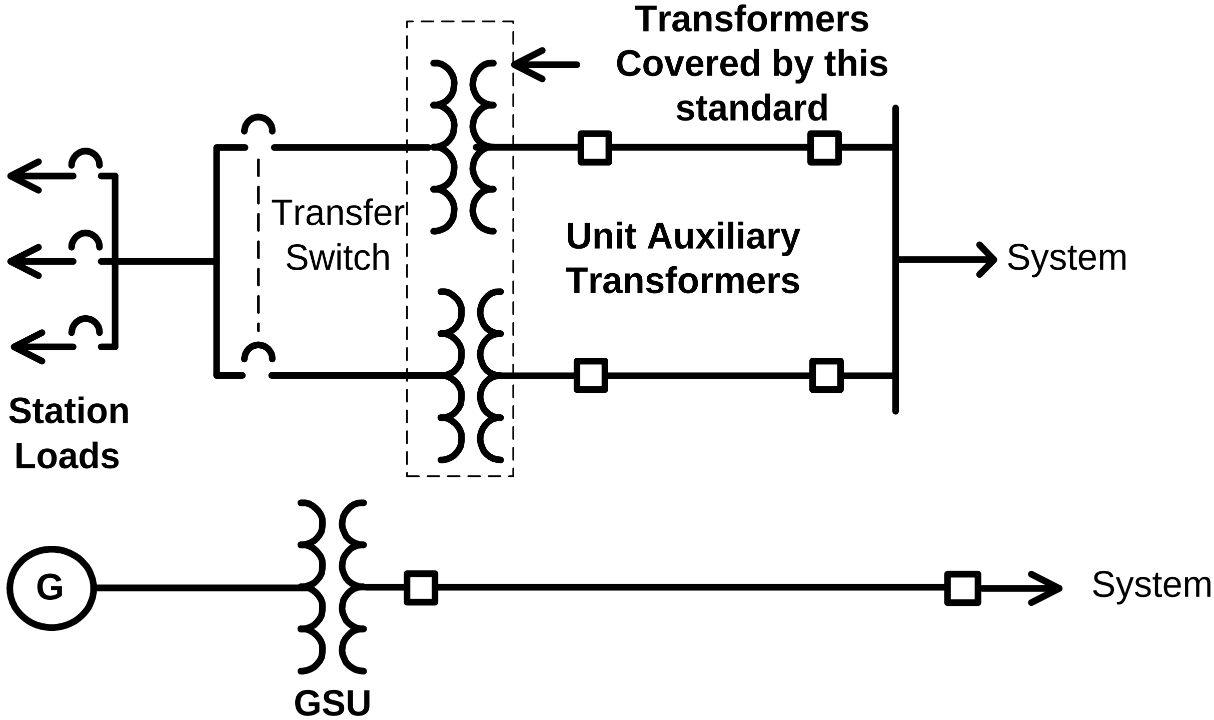


Figure ~~6 –~~ 7: Auxiliary Power System (independent from generator~~).~~)

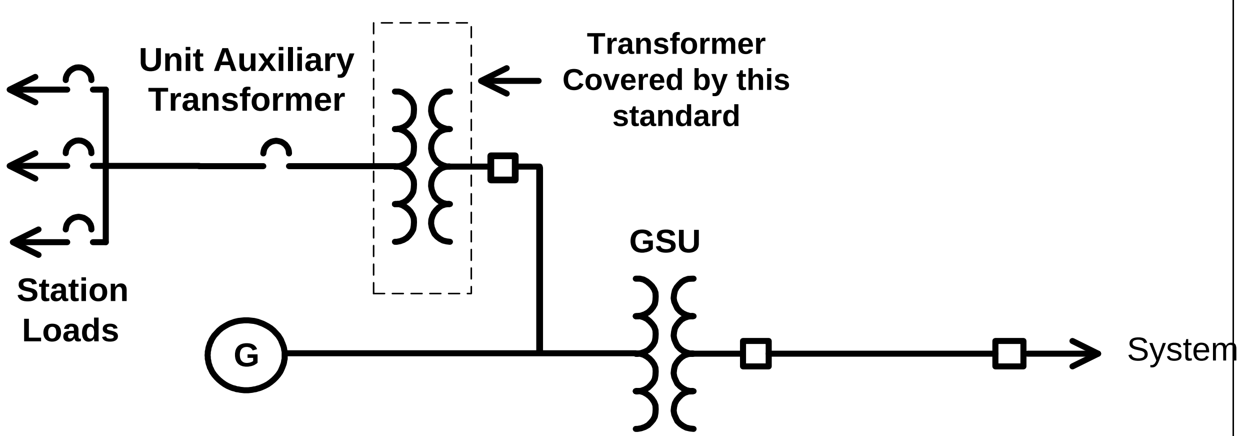


Figure ~~7 –~~ 8: Typical auxiliary power system for generation units or plants~~.~~

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the

transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the ~~entity's~~ relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system ~~(e.g., at the remote end of the line)~~ that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system ~~(e.g., at the remote end of the line)~~ that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

~~Relays applied on~~Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options ~~differs~~differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations~~:~~	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations~~:~~	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle-58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

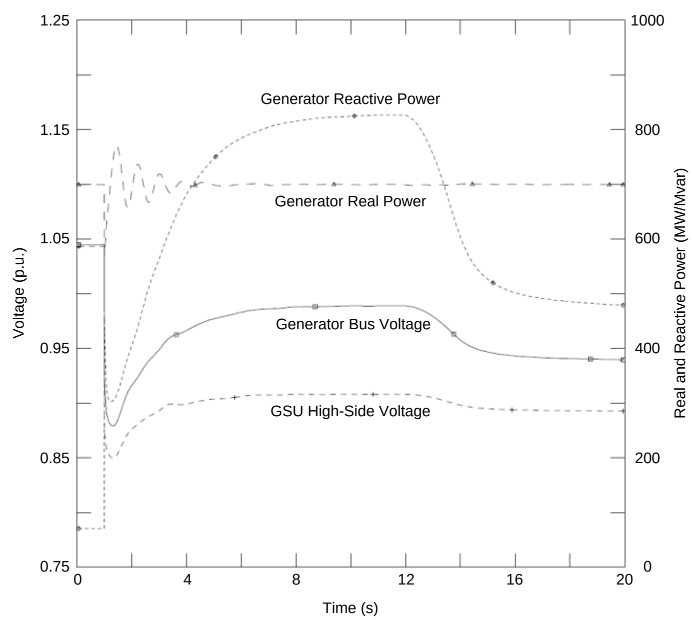
$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

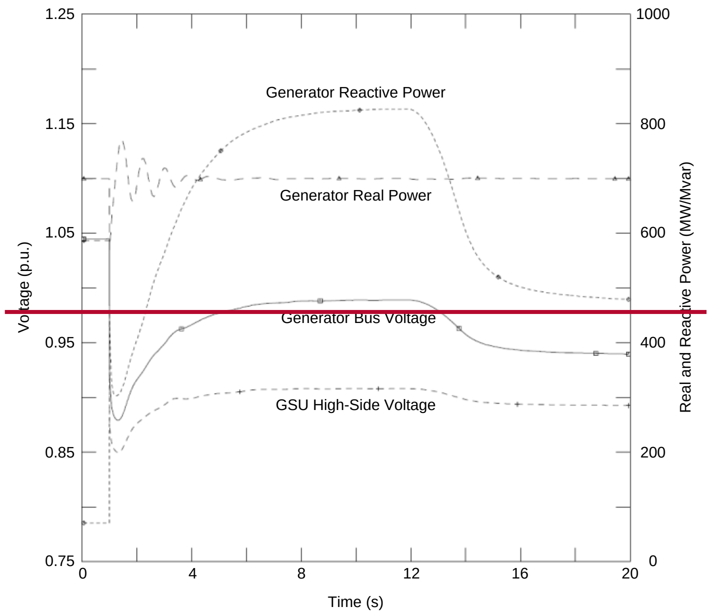
$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \dfrac{V^2_{bus\_simulated}}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Example Calculations: Option 2a

Real Power output (P):

Eq. (29) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Example Calculations: Option 2a

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (*MVA_{base}*).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

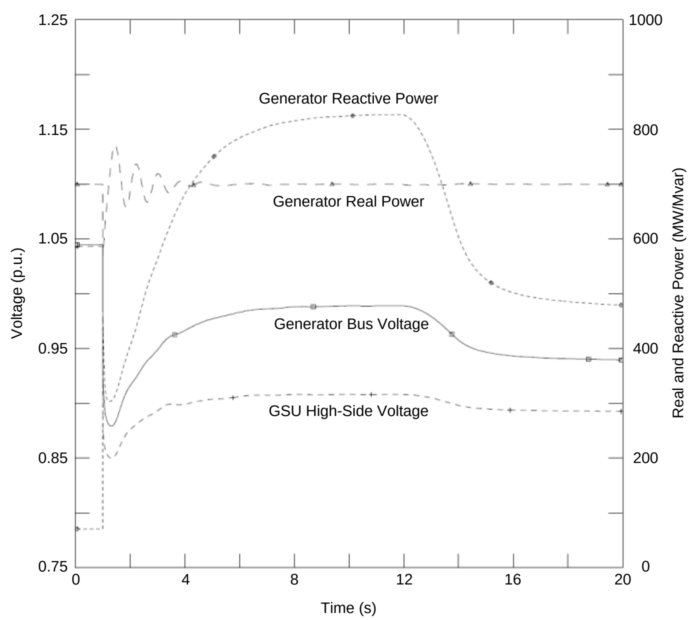
Example Calculations: Option 2b

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

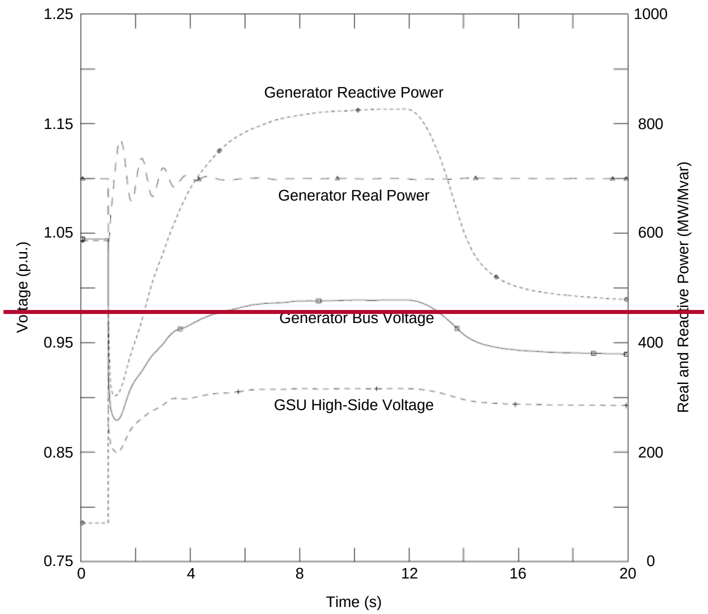
$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

Example Calculations: Option 2c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Example Calculations: Option 2c

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

Example Calculations: Option 4

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < \ 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{gen}}$

Example Calculations: Option 5a

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Option 5b

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

Example Calculations: Option 5b

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) ~~with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).~~See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

Example Calculations: Options 7a and 10

$$P_{Asynch} = 3 \times 40\ MVA\ \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + \ 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30\ \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

Example Calculations: Options 7a and 10

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 8a and 9a

Primary current (I_{pri}):

Eq. (93) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8b and 9b

Reactive Power output (Q):

Eq. (97) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (98) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $X_{pu} = X_{GSU(old)} \times \dfrac{MVA_{base}}{MVA_{GSU}}$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Example Calculations: Options 8b and 9b

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

Example Calculations: Options 8b and 9b

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

Example Calculations: Options 8a, 9a, 11, and 12

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S_{Synch}^{*}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle - 58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle - 58.7°\ A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA\ \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Example Calculations: Options 8a, 9a, 11, and 12

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1\ \angle -39.2°\ MVA}{1.73\ \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061\ \angle -58.7°\ A}{\frac{25000}{5}} + \frac{4755\angle -39.2°\ A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle -56.8°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $I_{sec\,limit} > I_{sec} \times 100\%$

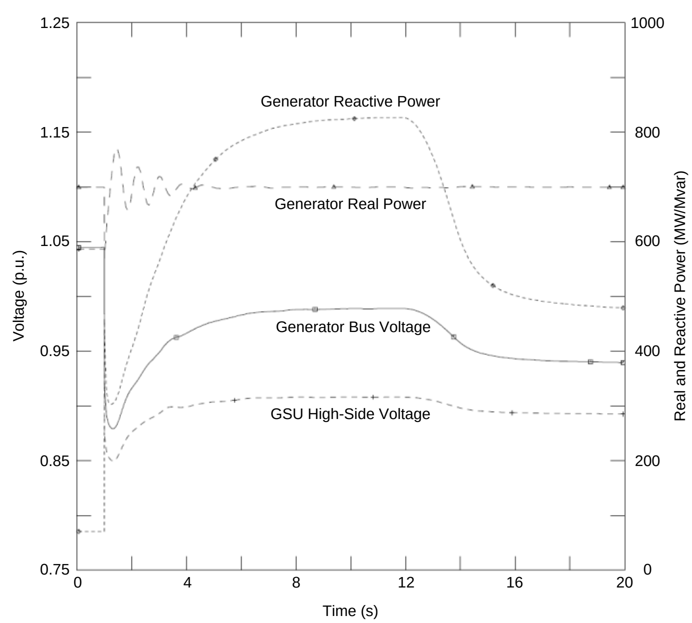
$$I_{sec\,limit} > 9.514\angle - 56.8°\ A \times 1.00$$

$$I_{sec\,limit} > 9.514\angle - 56.8°\ A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.



Example Calculations: Options 8c and 9c

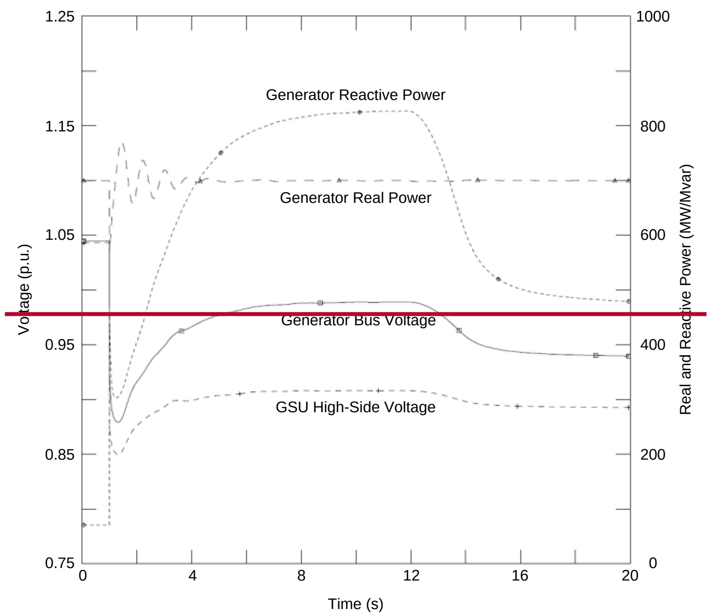
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (122) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: ~~Option10~~Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: ~~Option10~~Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: ~~Option10~~Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle -39.2° \ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \ MVA}{1.73 \times 13.8 \ kV}$$

$$I_{pri} = 2510.2 \ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51 \ A \times 1.50$$

$$I_{\sec limit} > 3.77 \ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77^{\circ}\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77^{\circ}$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle-52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

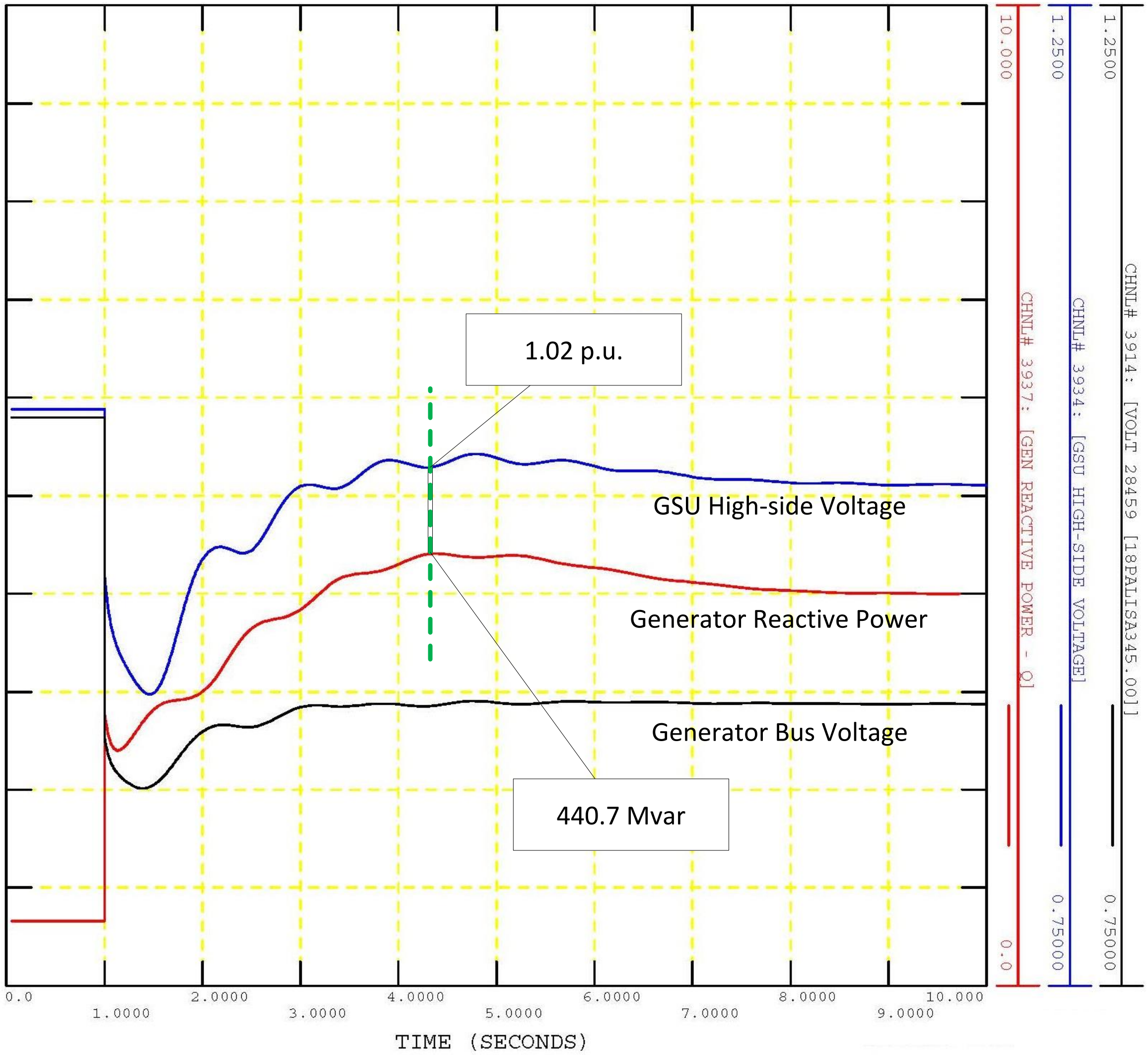
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and ~~high-side bus voltage~~coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~these values will correspond to the lowest apparent impedance~~.~~ at the relay location. The corresponding ~~high-side bus~~simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



~~In this simulation the following values are derived:~~

In this simulation the following values are derived:

$$\cancel{V_{bus\_simulated} = 0.908 \times V_{nom}}$$
$$\cancel{= 313.3\ kVQ}$$
$$= 440.7\ Mvar$$

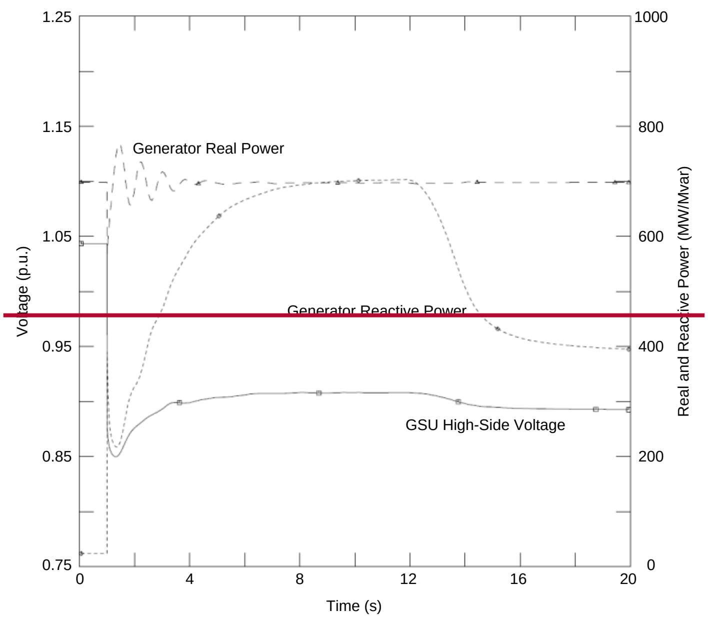
~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:~~

$$V_{bus\_simulated} = 1.02 \times V_{nom}$$
$$= 351.9\ kV$$

Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (152) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + \cancel{j703.6} j440.7\ Mvar$$

$$S = \cancel{992.5\angle 45.1} 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = \cancel{45.1} 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \cancel{\frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}} \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$Z_{pri} = \cancel{98.90\angle 45.1} 149.7\angle 32.2°\ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = \cancel{98.90\angle 45.1}149.7\angle 32.2° \,\Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = \cancel{98.90\angle 45.1}149.7\angle 32.2° \,\Omega \times 0.2$$

$$Z_{sec} = \cancel{19.78\angle 45.1}29.9\angle 32.2° \,\Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \cancel{\frac{19.78\angle 45.1° \,\Omega}{1.15}} \frac{29.9\angle 32.2° \,\Omega}{1.15}$$

$$Z_{\sec limit} = \cancel{17.20\angle 45.1}26.0\angle 32.2° \,\Omega$$

$$\theta_{transient\ load\ angle} = \cancel{45.1}32.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{17.20\,\Omega}{\cos(85.0° - 45.1°)}} \frac{26.0\,\Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \cancel{\frac{17.20\,\Omega}{0.767}} \frac{26.0\,\Omega}{0.61}$$

$$Z_{max} < \cancel{22.42}43.0\angle 85.0° \,\Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer ~~and~~ , including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer ~~and~~, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer~~. The~~ and the 0.85 per unit of the line nominal voltage at ~~the relay location will be~~ at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Example Calculations: Options 15a and 16a

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle -52.8°\ A$$

Example Calculations: Options 15a and 16a

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $V_{bus\_remote\_substation} = 0.85\ p.u. \times V_{nom}$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Example Calculations: Options 15a and 16a

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8° \, A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle - 52.8° \, A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701 \angle - 52.8° \, A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle - 52.8° \, A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

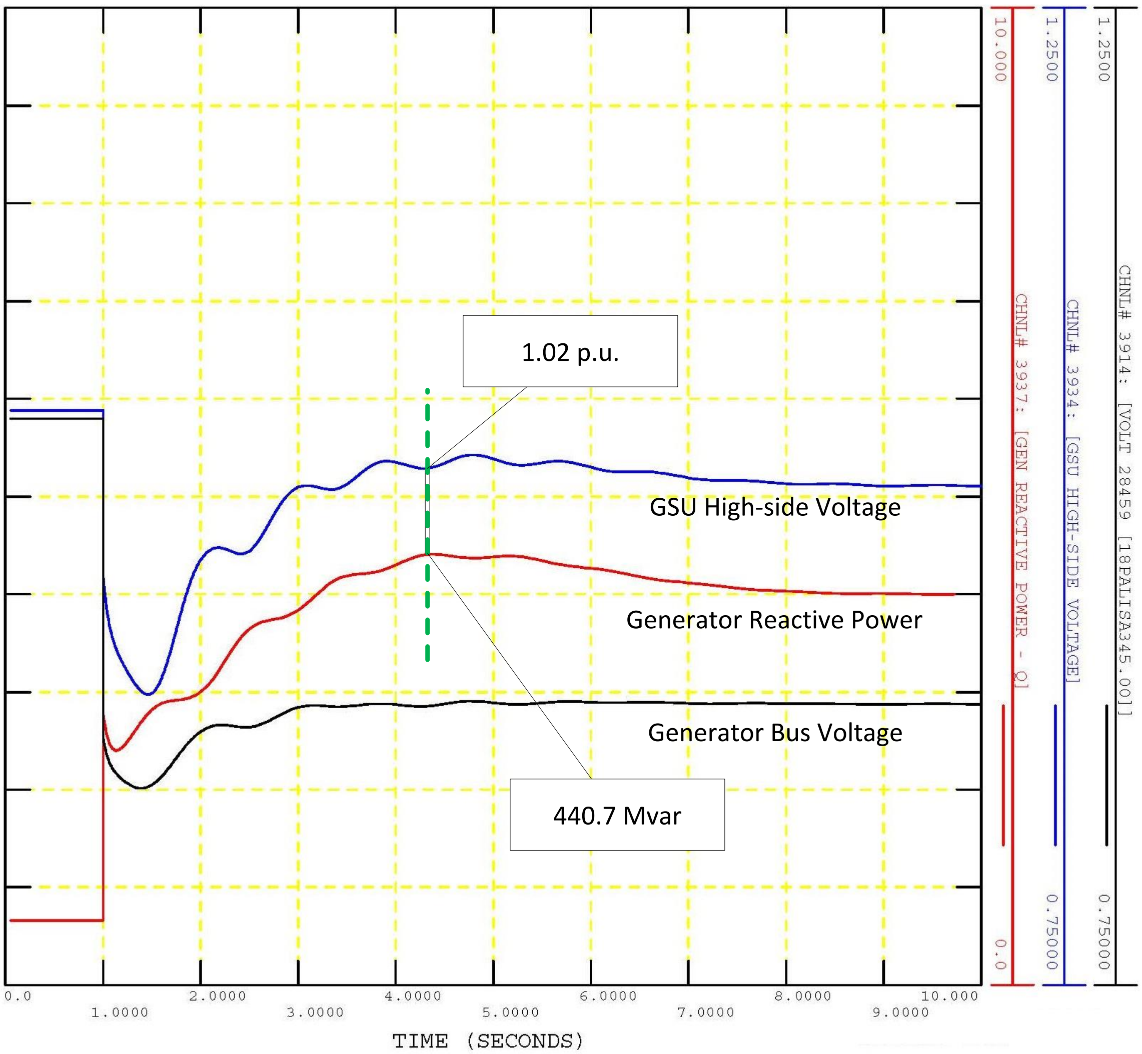
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer ~~and~~ , including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU and at the remote end of the line~~ and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU ~~and~~, including relays at the remote end of the line.

Example calculations are provided for the case~~,~~ where ~~PTs and CTs~~relays are ~~located at the~~ installed on the high-side of the GSU transformer, including relays installed on the remote end of ~~the~~ line ~~from the plant. The~~. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~is applied~~ at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and ~~high-side bus voltage~~coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~these values will correspond to the lowest apparent impedance~~.~~ at the relay location. The corresponding ~~high-side bus~~simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

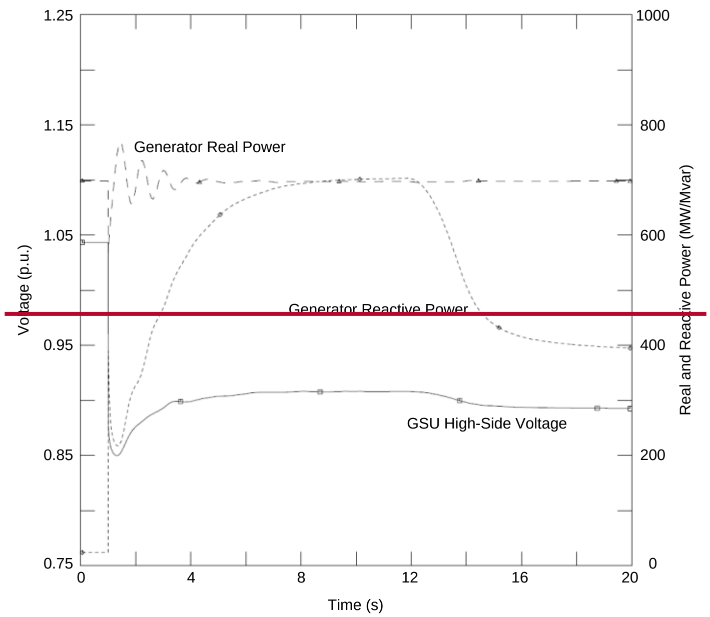
$$Q = \cancel{703.6}440.7\ Mvar$$

$$V_{bus\_simulated} = \cancel{0.908}1.02 \times V_{nom} = \cancel{313.3}351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 15b and 16b



Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + \cancel{j703.6}\, j440.7\ Mvar$$

$$S = \cancel{992.5\angle 45.1}\, 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \cancel{\frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}}\, \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = \cancel{1831}\, 1357.1\angle -32.2 \cancel{\angle -45.1}°\ A$$

Secondary current (I_{sec}):

Eq. (173) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio\_hv}}$

$$I_{sec} = \cancel{\frac{1831.2\angle -45.1°\ A}{\frac{2000}{5}}}\, \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

Example Calculations: Options 15b and 16b

$$I_{sec} = \cancel{4.578 \angle -45.1}3.39 \angle -32.2° \ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > \cancel{4.578 \angle -45.1}3.39 \angle -32.2° \ A \times 1.15$$

$$I_{\sec limit} > \cancel{5.265 \angle -45.1}3.90 \angle -32.2° \ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (175) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \ MVA \ \times 0.85$$

$$P_{Asynch} = 102.0 \ MW$$

Reactive Power output (Q):

Eq. (176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15 \ Mvar + 5 \ Mvar + (3 \times 40 \ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $$V_{bus} = 1.0 \ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345 \ kV$$

Example Calculations: Option 17

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Example Calculations: Option 17

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer ~~and~~, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer ~~and~~, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Example Calculations: Options 18 and 19

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

Example Calculations: Options 18 and 19

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-~~1~~2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

4.1.2. Transmission Owner that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

4.1.3. Distribution Provider that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

4.2.1. Generating unit(s).

4.2.2. Generator step-up (i.e., GSU) transformer(s).

4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~, except that Elements may also supply generating plant loads.

4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

~~6.1. **Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf~~)~~).

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 Compliance Enforcement Authority (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 Generator Owner, Transmission Owner, and Distribution Provider 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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 Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

~~Table of Compliance Elements~~

.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

~~E. Interpretations~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	

~~PRC-025-1~~2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads~~.),~~), the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Merged Cells

Inserted Cells

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) ~~– installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 15~~	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[7] If the relay is installed on the high-side of the GSU transformer use Option 15.

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>~~Pickup~~ Setting Criteria</th></tr>
<tr><td rowspan="5">Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators</td><td rowspan="5">Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer~~
~~If the relay is installed on the high-side of the GSU transformer use Option 16~~</td><td>9a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>9b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>9c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The overcurrent element shall be set greater than 115% of the calculated current derived from:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="5">A different application starts on the next page</td></tr>
</table>

[8] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51)~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[9] If the relay is installed on the high-side of the GSU transformer use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
~~Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)~~	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 19[11]~~	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		

[11] If the relay is installed on the high-side of the GSU transformer use Option 19.

Merged Cells

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	side terminals of the UAT, for which operation of the relay will cause the associated generator to trip~~.~~	13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ –) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 7~~	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or phase time overcurrent relay (e.g., 51)~~—~~ ~~installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

[13] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based,	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[14] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant load~~.~~.) –connected to synchronous generators	communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~	16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 10~~	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or Phase time overcurrent relay (e.g., 51)~~—installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 11~~	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or Phase directional time overcurrent relay (e.g., 67)~~—installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 12~~	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

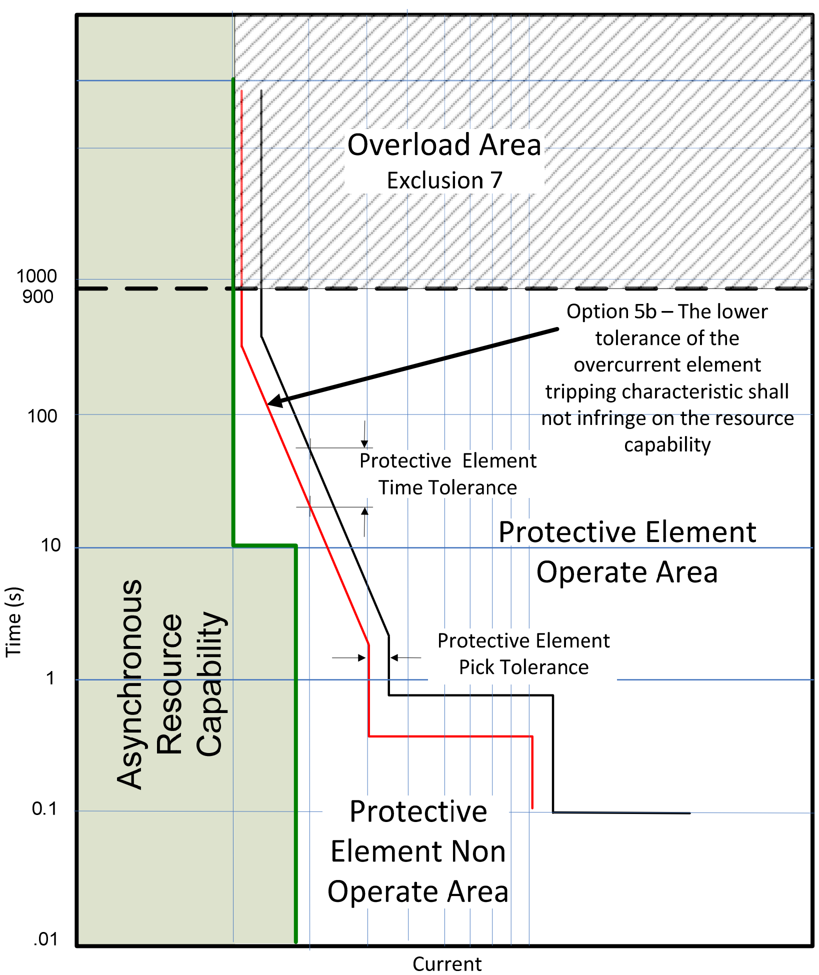


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both

---

18 http://www.nerc.com/~~docs/pc/spctf/~~comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20 Gen%20Prot%~~20Coord%20Rev1%20Final%2007-30-2010~~20Coordination%20Technical%20Reference%20Document.pdf.

within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

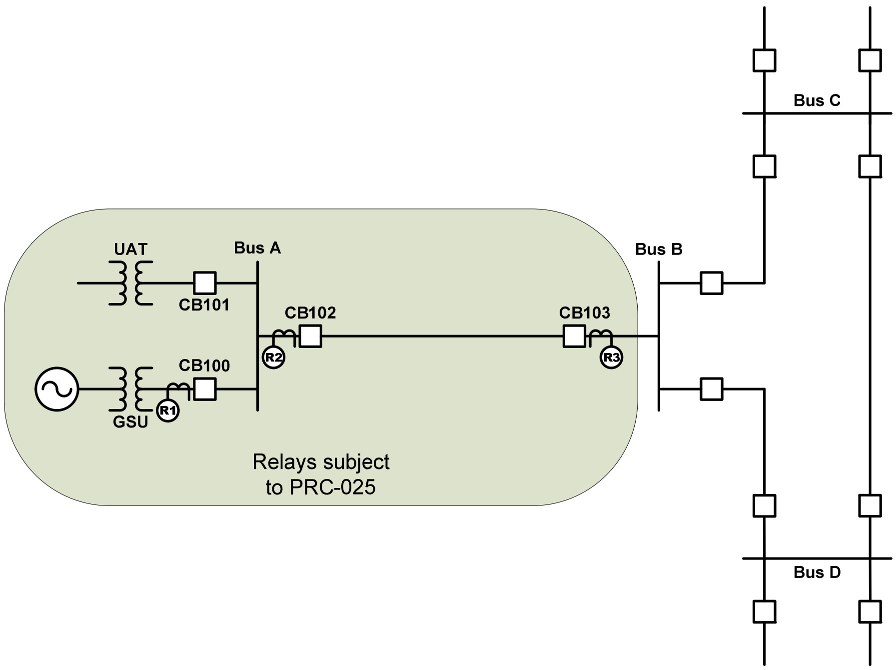
The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of

Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.
~~In this particular case,~~
Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable ~~responsible entity's~~ to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional ~~relay R3 located on breaker CB103 at Bus B looking~~ toward ~~Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not~~the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in ~~this~~the standard~~ or~~. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased ~~transmission system loading~~generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in ~~PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1~~ this standard.~~ PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


Bus C
UAT
Bus A
Bus B
CB101
CB102
CB103
R2
R3
CB100
R1
GSU
Relays subject
to PRC-025
Bus D

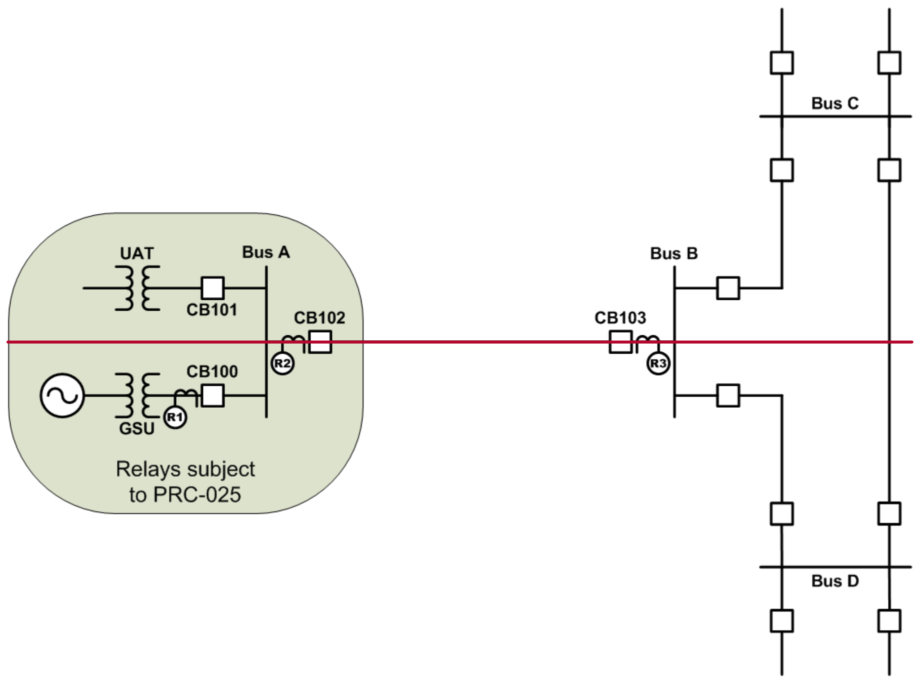


Figure 1~~.~~: Generation exported through a single radial line~~.~~

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

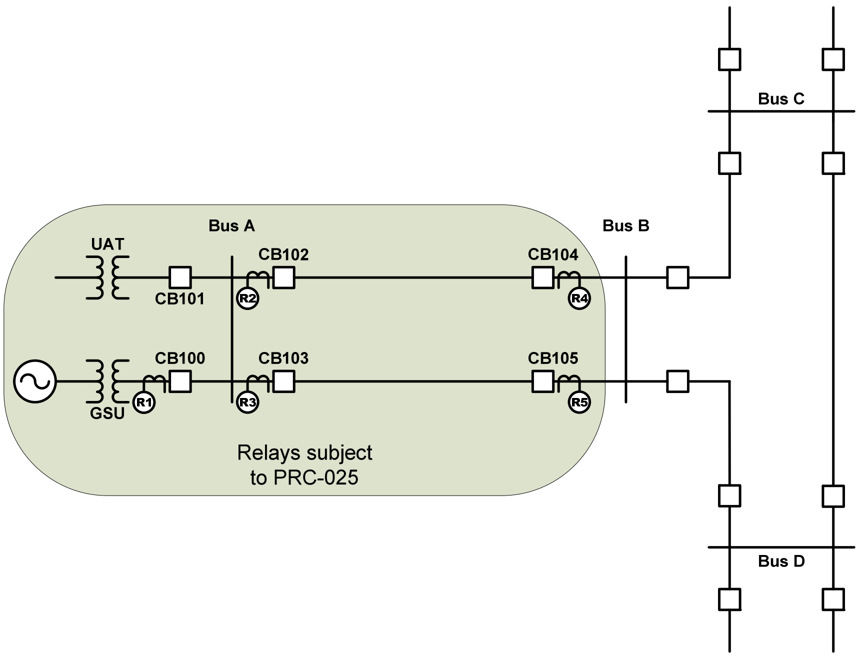


Figure 2~~.~~: Generation exported through multiple radial lines~~.~~

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

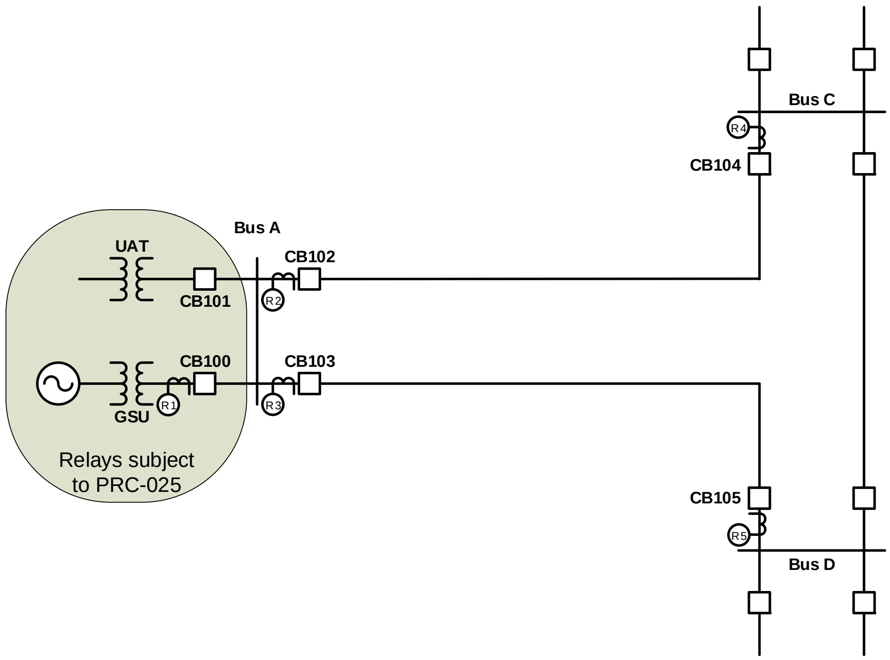


Figure 3~~.~~: Generation exported through a network~~.~~

~~Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.~~

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

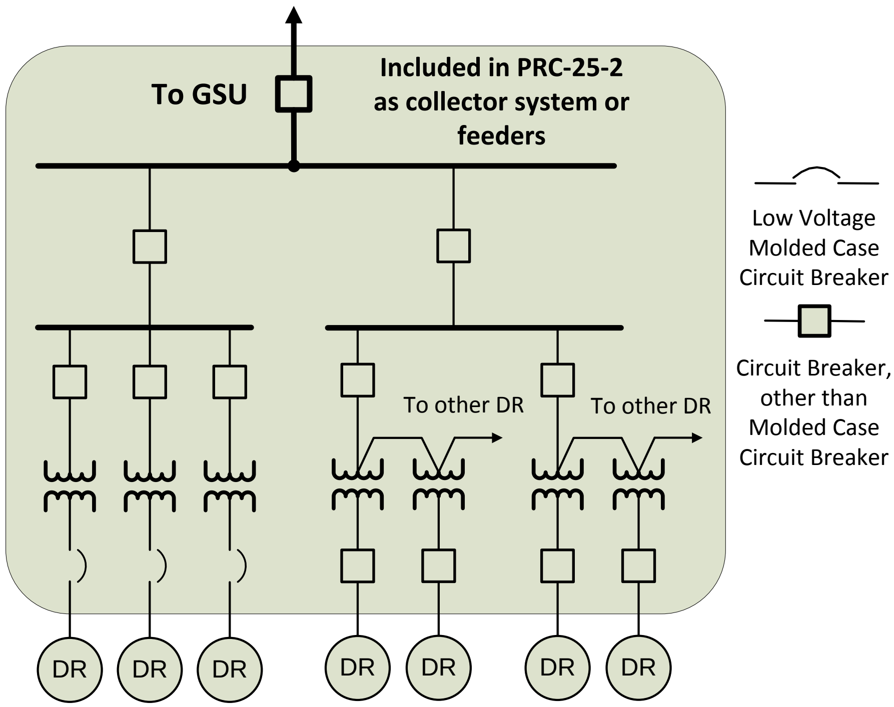


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure ~~5~~6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage ~~to be used~~at the relay location to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the*

> *system protection engineers **to optimize coordination while still protecting the turbine generator**. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions. **Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.** With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options differ from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options differ from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures ~~4~~5 and ~~5~~6 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

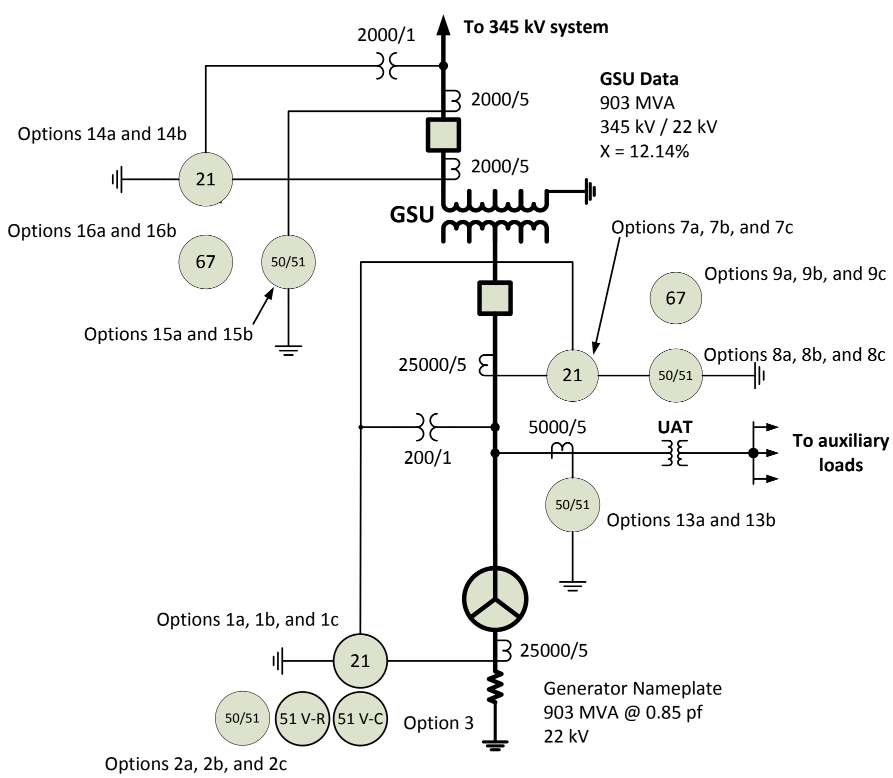


Figure ~~4.~~5: Relay Connection for corresponding synchronous options~~.~~

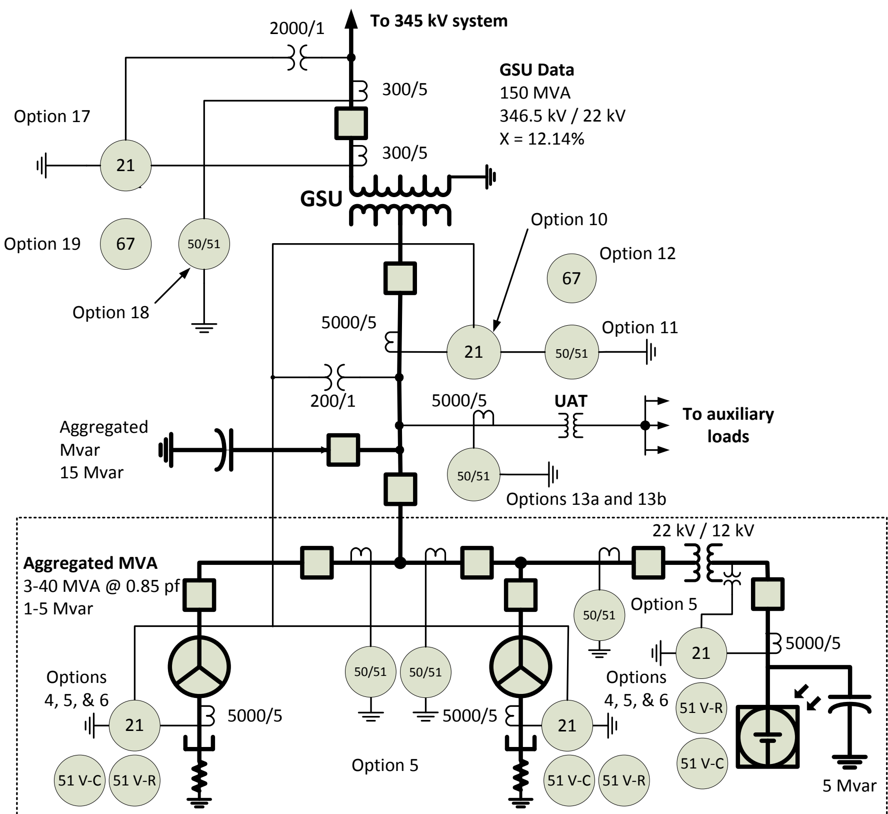


Figure ~~5.~~6: Relay Connection for corresponding asynchronous options including inverter-based installations~~.~~

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage ~~-~~Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~("voltage~~-restrained~~")~~). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage -Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b))

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~(“voltage~~-restrained~~”).~~). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~These margins are based on guidance found in section 3.~~Note that the setting criteria established within the Table 1 ~~of the~~options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options ~~7a, 7b~~8a, 8b, and ~~7c~~8c, are provided for assessing loadability ~~for GSU transformers applying~~of phase ~~distance~~overcurrent relays that are ~~directional toward the Transmission system on synchronous generators that are~~ connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option ~~14.~~
~~Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer.~~ 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.
~~Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer.~~

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. ~~The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.~~ The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more

~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option ~~7a~~8a.

Option ~~7c~~8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~ in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall.~~

~~For~~than Options ~~7a~~8a or 8b.

For Options 8a and ~~7b~~8b, the ~~impedance~~overcurrent element ~~is~~shall be set ~~less~~greater than 115 percent of the calculated ~~impedance~~current derived from ~~115 percent of: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~both
~~For Option 7c, the impedance element is set less than the calculated impedance derived from 115 percent of~~: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~Directional Overcurrent Relay ~~(51~~– Directional Toward Transmission System (e.g., 67) (Options ~~8a, 8b~~9a, 9b and ~~8c~~9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.~~
~~Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by~~

~~multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.~~

~~Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.~~

~~Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~
~~For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~

~~For Option 8c, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.~~

~~Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.
~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; ~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~ hence ~~Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

~~For Option 11, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

~~Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.~~

~~Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~

~~Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~ the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option ~~12~~11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. ~~Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.~~

Refer to the Figures ~~6~~7 and ~~7~~8 below for example configurations:

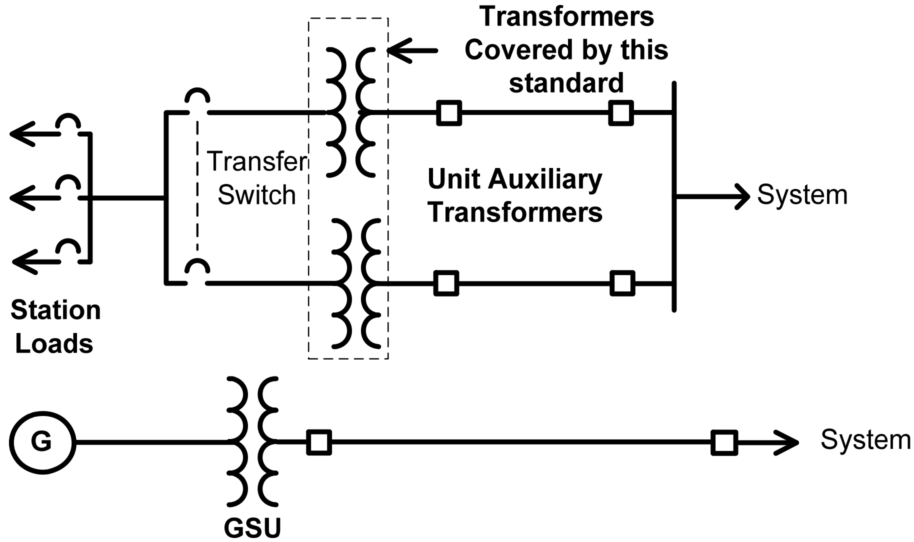


Figure ~~6~~ 7: Auxiliary Power System (independent from generator~~)~~)

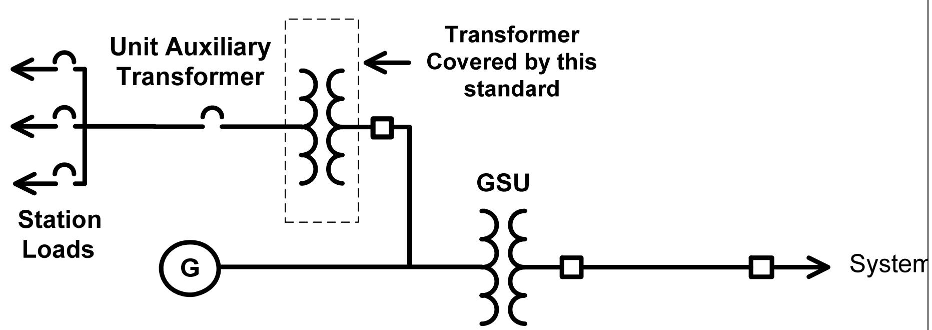


Figure ~~7~~ 8: Typical auxiliary power system for generation units or plants~~.~~

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the

transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the ~~entity's~~ relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for

Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on

Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional~~ time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$ $pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~ 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

~~Eq. (15)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

~~Eq. (17)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~ 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}} \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

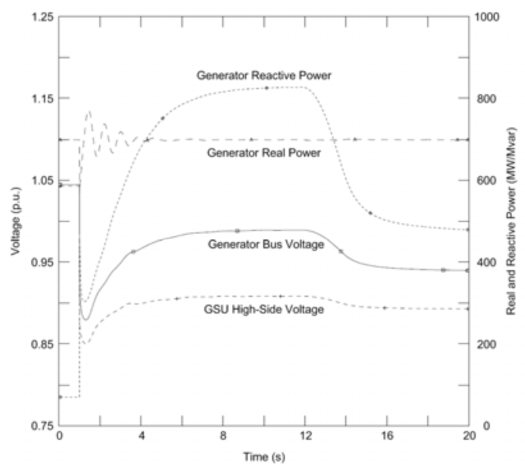
Example Calculations: Options 1c and 7c

~~Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.~~

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~In this simulation the following values are derived:~~



Example Calculations: Options 1c and 7c

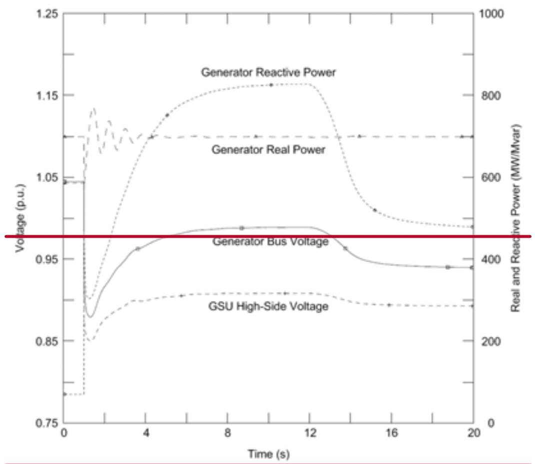
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$\cancel{V_{bus}} V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\mathrm{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \cancel{\frac{V_{bus}^2}{S^*}} \frac{V_{bus\_simulated}^2}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

Example Calculations: Options 1c and 7c

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~ 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \cancel{\frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}} \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

Example Calculations: Option 2a

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7°$$

Eq. (42)

~~Eq. (42)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

~~Eq. (44)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

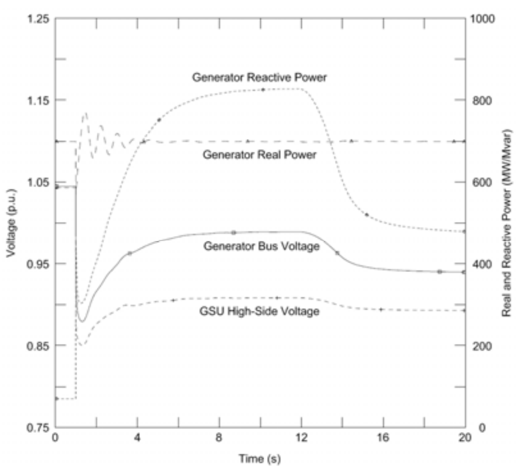
Example Calculations: Option 2b

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.In this simulation the following values are derived:~~

Example Calculations: Option 2c

In this simulation the following values are derived:

~~$Q = 827.4\ Mvar$~~

Deleted Cells

~~$V_{bus} = 0.989 \times V_{gen\_nom}$~~ $= Q = 827.4\ Mvar$ ~~$21.76\ kV$~~

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:~~

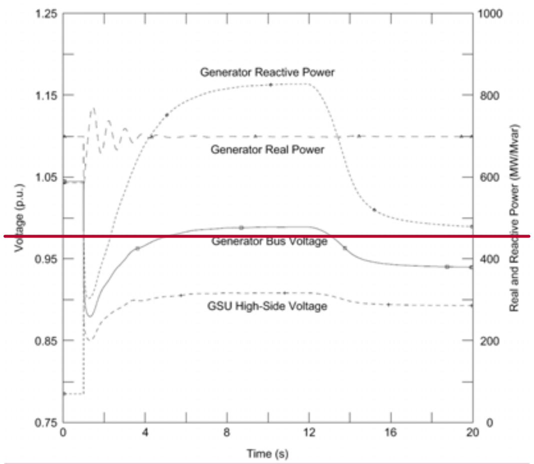
$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$

Inserted Cells

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

~~$P_{Synch\_reported} = 700.0\ MW$~~

Deleted Cells



$P_{Synch\_reported} = 700.0\ MW$

Inserted Cells

Apparent power (S):

Eq. (50) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Example Calculations: Option 2c

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \cancel{\frac{S}{\sqrt{3} \times V_{bus}}} \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) ~~voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Options 3 and 6

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = \ GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Option 4

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Example Calculations: Option 4

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option ~~5~~5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage-restrained~~ relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option ~~5~~5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option ~~5~~5a

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option ~~5~~5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: ~~Options 7a and 10~~Option 5b

~~This~~Similarly to Option 5a, this example represents the calculation for ~~a mixture of~~three asynchronous ~~(i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations)~~generators applying a phase ~~distance~~overcurrent (e.g., 50, 51, or 51V-R) relay ~~(21) directional toward the Transmission system.~~. In this application it was assumed that 20 Mvar of total static compensation was added.

~~**Synchronous Generation (Option 7a)**~~

Real Power output (~~P_{sync}):~~P):

Eq. (71) $\cancel{P_{synch} = GEN_{synch\_nameplate} \times pf} P = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: ~~Options 7a and 10~~Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

~~Example Calculations: Options 7a and 10~~

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $Q_{Synch} = 150\% \times P_{Synch}$

$Q_{Synch} = 1.50 \times 767.6\ MW$

$Q_{Synch} = 1151.3\ MW$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~84 to satisfy the margin requirements in Options 7a and 10~~:~~.

Eq. (~~81~~87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (~~84~~90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (~~86~~92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~87~~93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (~~88~~94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more ~~complex~~precise calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~90~~96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~91~~97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (~~93~~99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (~~94~~100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low-side}$) using 0.85 p.u. high-side voltage ($V_{high-side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low-side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

~~Eq. (96)~~ $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

Deleted Cells

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\, p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

~~Eq. (98)~~

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105)

$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

Deleted Cells

Example Calculations: Options 8b and 9b

$$V_{bus} = 0.9998\, p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (~~102~~108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Options 8a, 9a, 11, and 12

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114)
$$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115)
$$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA\ \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a, 9a, 11, and 12

Apparent power (S_{Asynch}):

Eq. (~~112~~118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1\ \angle -39.2°\ MVA}{1.73\ \times 20.81\ kV}$$

$$I_{pri-async} = 4755\ \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~114~~120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061\ \angle -58.7°\ A}{\frac{25000}{5}} + \frac{4755\angle -39.2°\ A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle -56.8°\ A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98.~~118.

Eq. (~~115~~121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle -56.8°\ A \times 1.00$$

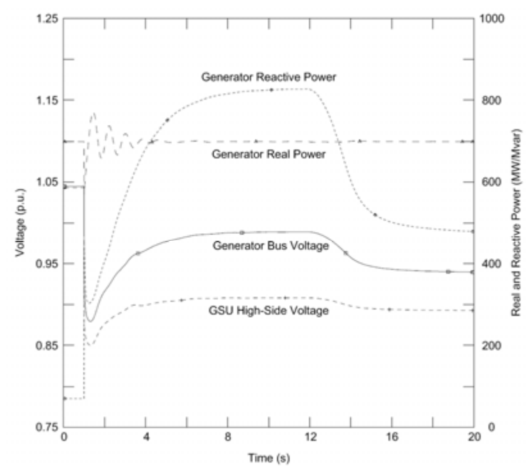
$$I_{\sec limit} > 9.514\angle -56.8°\ A$$

Example Calculations: Options 8c and 9c

~~This example uses Option 15b as a simulation example for a synchronous generator applying a phase time overcurrent relay. In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.~~

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used ~~as~~since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$\cancel{V_{bus}}V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 8c and 9c

Apparent power (S):

Eq. (122) $S = P_{Synch\_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8\angle 49.8°$

Primary current (I_{pri}):

Eq. (123) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$

$I_{pri} = 28790\ A$

Secondary current (I_{sec}):

Eq. (124) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$

$I_{sec} = 5.758\ A$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $I_{\sec limit} > I_{sec} \times 115\%$

$I_{\sec limit} > 5.758\ A \times 1.15$

$I_{\sec limit} > 6.622\ A$

~~Example Calculations: Option 10~~

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

~~Example Calculations: Option 10~~

Real Power output (P):

Eq. (126) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

~~Example Calculations: Option 10~~

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < \ 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 11 and 12

$$I_{pri} = \frac{131.6 \angle -39.2° \; MVA}{1.73 \times 21.9 \; kV}$$

$$I_{pri} = 3473\angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2° \; A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2° \; A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2° \; A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \; A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \; MVA}{1.73 \times 13.8 \; kV}$$

$$I_{pri} = 2510.2 \; A$$

Example Calculations: Options 13a and 13b

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \mathrm{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

Example Calculations: Option 14a

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

Example Calculations: Option 14a

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

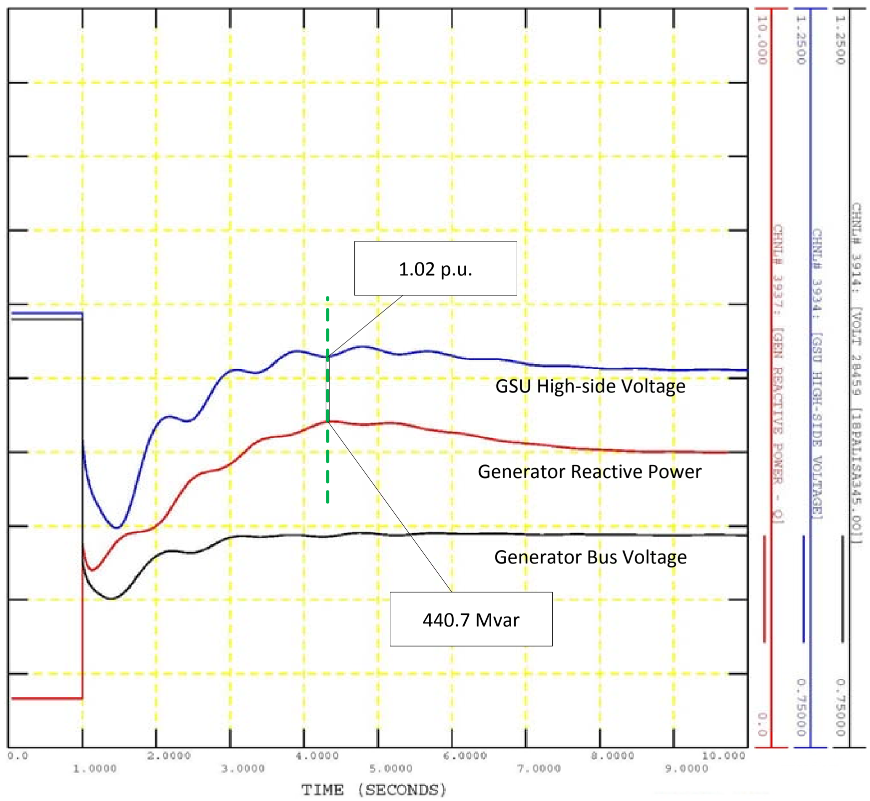
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

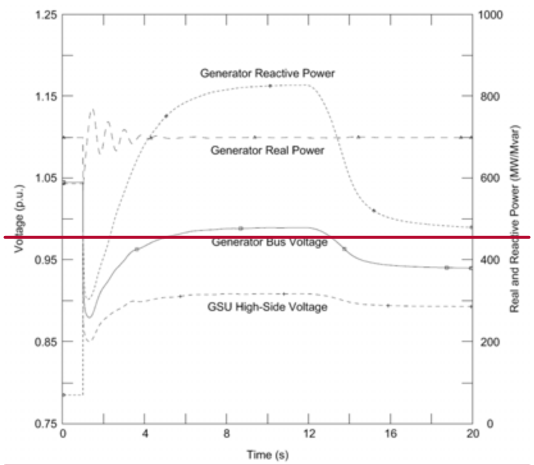
$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

~~Example Calculations: Option 14b~~



Apparent power (S):

Eq. (~~116~~152) $S = P_{Synch\_reported} + jQ$

$S = 700.0\ MW + \cancel{j827.4}\, j440.7\ Mvar$

$S = \cancel{1083.8\angle 49.8°}\, 827.2\angle 32.2°\ MVA$

$\theta_{transient\ load\ angle} = 32.2°$

Primary ~~current (I~~~~pri~~impedance (Z_{pri}):

Eq. (~~117~~153) $\cancel{I_{pri} = \frac{S}{\sqrt{3}\times V_{bus}}}\, Z_{pri} = \frac{V^2_{bus\_simulated}}{S^*}$

$\cancel{I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}}\, Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$

$\cancel{I_{pri} = 28790\ A}\, Z_{pri} = 149.7\angle 32.2°\ \Omega$

Secondary ~~current (I~~~~sec~~impedance (Z_{sec}):

Eq. (~~118~~154) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}\, \cancel{I_{sec} = \frac{I_{pri}}{CT_{ratio}}}$

Example Calculations: Option 14b

$$\cancel{I_{sec} = \frac{28790\,A}{\frac{25000}{5}}}\; Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$\cancel{I_{sec} = 5.758\,A}\; Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in ~~Options 8c and 9c~~Option 14b:

Eq. (~~119~~155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}\; \cancel{I_{sec\,limit} > I_{sec} \times 115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 18a

$$\cancel{I_{sec\,limit} > 5.758\,A \times 1.15}$$

$$\cancel{I_{sec\,limit} > 6.622\,A}$$

~~Example Calculations: Option10~~

~~This represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.~~

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

~~Eq. (120)~~ $\cancel{P = 3 \times GEN_{Asych\_nameplate} \times pf}$

$\cancel{P = 3 \times 40\ MVA \times 0.85}$

$\cancel{P = 102.0\ MW}$

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

~~Example Calculations: Option10~~

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

~~Eq. (121)~~ $\cancel{Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)}$

$$\cancel{Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))}$$

$$\cancel{Q = 83.2\ Mvar}$$

~~Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):~~

~~Eq. (122)~~ $\cancel{V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}}$

$$\cancel{V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)}$$

$$\cancel{V_{gen} = 21.9\ kV}$$

Apparent power (S):

~~Eq. (123)~~ $\cancel{S = P + jQ}$

$$\cancel{S = 102.0\ MW + j83.2\ Mvar}$$

$$\cancel{S = 131.6\angle 39.2°\ MVA}$$

~~Primary impedance (Z_{pri}):~~

~~Eq. (124)~~ $\cancel{Z_{pri} = \frac{V_{gen}^2}{S^*}}$

$$\cancel{Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}}$$

Example Calculations: Option10

$$\cancel{Z_{pri} = 3.644\angle 39.2°\ \Omega}$$

~~Secondary impedance (Z_{sec}):~~

~~Eq. (125)~~ $$\cancel{Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}}$$

$$\cancel{Z_{sec} = 3.644\angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}}$$

$$\cancel{Z_{sec} = 3.644\angle 39.2°\ \Omega \times 5}$$

$$\cancel{Z_{sec} = 18.22\angle 39.2°\ \Omega}$$

~~To satisfy the 130% margin in Option 10:~~

~~Eq. (126)~~ $$\cancel{Z_{sec\,limit} = \frac{Z_{sec}}{130\%}}$$

$$\cancel{Z_{sec\,limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}}$$

$$\cancel{Z_{sec\,limit} = 14.02\angle 39.2°\ \Omega}$$

$$\cancel{\theta_{transient\,load\,angle} = 39.2°}$$

~~Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:~~

~~Eq. (127)~~ $$\cancel{Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\,load\,angle})}}$$

$$\cancel{Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}}$$

$$\cancel{Z_{max} < \frac{14.02\ \Omega}{0.6972}}$$

$$\cancel{Z_{max} < 20.11\angle 85.0°\ \Omega}$$

Eq. (160) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

~~Example Calculations: Options 11 and 12~~
~~Option 11 represents the calculation for a GSU transformer applying a phase time overcurrent (51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent relay (67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.~~

~~Real Power output (P):~~

~~Eq. (128)~~ ~~$P = 3 \times GEN_{Asynch\_nameplate} \times pf$~~

~~$P = 3 \times 40\ MVA \times 0.85$~~

~~$P = 102.0\ MW$~~

~~Reactive Power output (Q):~~

~~Eq. (129)~~ ~~$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$~~

~~$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$~~

~~$Q = 83.2\ Mvar$~~

~~Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):~~

~~Eq. (130)~~ ~~$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$~~

~~$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$~~

~~$V_{gen} = 21.9\ kV$~~

~~Apparent power (S):~~

~~Eq. (131)~~ ~~$S = P + jQ$~~

~~$S = 102.0\ MW + j83.2\ Mvar$~~

~~$S = 131.6\angle 39.2°\ MVA$~~

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

~~Eq. (132)~~ $$I_{pri}=\frac{S^*}{\sqrt{3}\times V_{gen}}$$

$$I_{pri}=\frac{131.6\angle-39.2°\,MVA}{1.73\times 21.9\,kV}$$

$$I_{pri}=3473\angle-39.2°\,A$$

Secondary current (I_{sec}):

~~Eq. (133)~~ $$I_{sec}=\frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec}=\frac{3473\angle-39.2°\,A}{\frac{5000}{5}}$$

$$I_{sec}=3.473\angle-39.2°\,A$$

~~To satisfy the 130% margin in Options 11 and12:~~

~~Eq. (134)~~ $$I_{sec\,limit}>I_{sec}\times 130\%$$

$$I_{sec\,limit}>3.473\angle-39.2°\,A\times 1.30$$

$$I_{sec\,limit}>4.515\angle-39.2°\,A$$

~~Example Calculations: Options 13a and 13b~~

~~Option 13a for the UAT assumes that the maximum nameplate rating of the winding utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.~~

~~Primary current~~ ~~(I_{pri}):~~

~~Eq. (135)~~ $$I_{pri}=\frac{UAT_{nameplate}}{\sqrt{3}\times V_{UAT}}$$

$$I_{pri}=\frac{60\,MVA}{1.73\times 13.8\,kV}$$

$$I_{pri}=2510.2\,A$$

~~Secondary current~~ ~~(I_{sec}):~~

~~Eq. (136)~~ $$I_{sec}=\frac{I_{pri}}{CT_{UAT}}$$

~~Example Calculations: Options 13a and 13b~~

$$\cancel{I_{sec} = \frac{2510.2\,A}{\frac{5000}{5}}}$$

$$\cancel{I_{sec} = 2.51\text{ A}}$$

~~To satisfy the 150% margin in Options 13a:~~

~~Eq. (137)~~ $\cancel{I_{sec\,limit} > I_{sec} \times 150\%}$

$$\cancel{I_{sec\,limit} > 2.51\,A \times 1.50}$$

$$\cancel{I_{sec\,limit} > 3.77\,A}$$

Eq. (162) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio\_hv}}$

$$I_{sec} = \frac{2280.6\angle -52.8°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\,A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.701\angle -52.8°\,A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\,A$$

~~Example Calculations: Option 14a~~

~~Option 14a represents the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.~~

Calculations at the remote end of the line from the plant.

Real Power output (P):

~~Eq. (138)~~ $\cancel{P = GEN_{synch\_nameplate} \times pf}$

Eq. (164) $P = GEN_{Synch\_nameplate} \times pf$

$P = 903\ MVA\ \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

~~Eq. (139)~~ $\cancel{Q = 120\% \times P}$

Eq. (165) $Q = 120\% \times P$

$Q = 1.20 \times 767.6\ MW$

$\cancel{Q = 921.1\ Mvar}$

~~Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage for the GSU transformer voltage (V_{nom}):~~

~~Eq. (140)~~ $\cancel{V_{bus} = 0.85\ p.u. \times V_{nom}}$

$Q = 921.12\ Mvar$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $V_{bus\_remote\_substation} = 0.85\ p.u. \times V_{nom}$

$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$

$V_{bus\_remote\_substation} = 293.25\ kV$

$\cancel{V_{gen} = 0.85 \times 345\ kV}$

$\cancel{V_{gen} = 293.25\ kV}$

Apparent power (S):

Eq. (167) $S = P_{Synch\_reported} + jQ$

$S = 700.0\ MW + j921.12\ Mvar$

$S = 1157\angle 52.8°\ MVA$

Primary current (I_{pri}):

Eq. (168) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$

$$I_{pri} = \frac{1157\angle - 52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle - 52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle - 52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle - 52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle - 52.8°\ A$$

Example Calculations: Options 15b and 16b

~~Eq. (141)~~ $$\cancel{S = P_{Synch\_reported} + jQ}$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

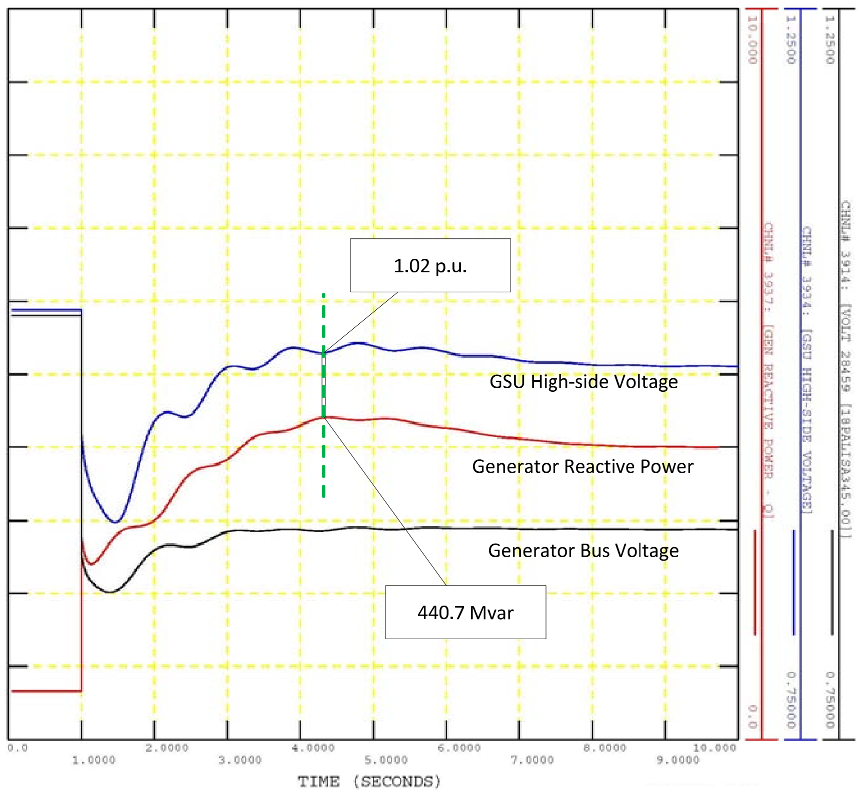
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

~~Example Calculations: Options 15b and 16b~~



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

$$\cancel{S = 700.0\ MW + j921.1\ Mvar}$$

$$\cancel{S = 1157.0\angle 52.77°\ MVA}$$

$$\cancel{\theta_{transient\ load\ angle} = 52.77°}$$

~~Example Calculations: Options 15b and 16b~~

~~Primary impedance (Z_{pri}):~~

~~Eq. (142)~~ $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

~~Secondary impedance (Z_{sec}):~~

~~Eq. (143)~~ $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

~~To satisfy the 115% margin in Option 14a:~~

~~Eq. (144)~~ $$Z_{sec\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\,limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{sec\,limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

~~Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:~~

~~Eq. (145)~~ $$Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

~~Example Calculations: Option 14b~~

~~Option 14b represents the simulation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.~~

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

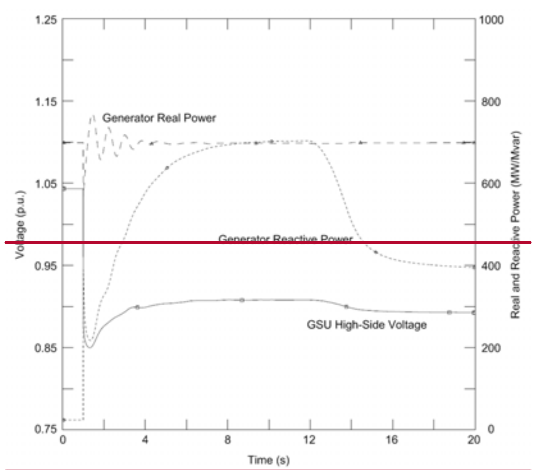
~~In this simulation the following values are derived:~~

$$\cancel{Q = 703.6\ Mvar}$$

$$\cancel{V_{bus} = 0.908 \times V_{nom} = 313.3\ kV}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~171) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + \cancel{j703.6}\, j440.7\ Mvar$$

Example Calculations: Option 14b

$$S = \cancel{992.5\angle 45.1}\,827.2\angle 32.2°\ MVA$$

$$\cancel{\theta_{transient\ load\ angle} = 45.1°}$$

Primary ~~impedance (Z_{pri}~~current (I_{pri}):

Eq. (~~147~~172) $$\cancel{Z_{pri} = \frac{V_{bus}^2}{S^*}}\ I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$\cancel{Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}}\ I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$\cancel{Z_{pri} = 98.90\angle 45.1°\ \Omega}\ I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary ~~impedance (Z_{sec}~~current (I_{sec}):

Eq. (~~148~~173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}\ \cancel{Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}}$$

$$\cancel{Z_{sec} = 98.90\angle 45.1°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}}\ I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$\cancel{Z_{sec} = 98.90\angle 45.1°\ \Omega \times 0.2}\ I_{sec} = 3.39\ \angle -32.2°\ A$$

$$\cancel{Z_{sec} = 19.78\angle 45.1°\ \Omega}$$

To satisfy the 115% margin in ~~Option 14b~~Options 15b and 16b:

Eq. (~~149~~174) $$I_{sec\,limit} > I_{sec} \times 115\%\ \cancel{Z_{sec\,limit} = \frac{Z_{sec}}{115\%}}$$

$$\cancel{Z_{sec\,limit} = \frac{19.78\angle 45.1°\ \Omega}{1.15}}$$

$$\cancel{Z_{sec\,limit} = 17.20\angle 45.1°\ \Omega}\ I_{sec\,limit} > 3.39\ \angle -32.2°\ A \times 1.15$$

$$\cancel{\theta_{transient\ load\ angle} = 45.1°}\ I_{sec\,limit} > 3.90\ \angle -32.2°\ A$$

~~Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:~~

~~Eq. (150)~~ $$\cancel{Z_{max} < \frac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}}$$

$$\cancel{Z_{max} < \frac{17.20\ \Omega}{\cos(85.0° - 45.1°)}}$$

~~Example Calculations: Option 14b~~

$\cancel{Z_{max} < \frac{17.20\,\Omega}{0.767}}$

$\cancel{Z_{max} < 22.42\angle 85.0°\,\Omega}$

~~Example Calculations: Options 15a and 16a~~

~~Options 15a and 16a represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15a represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16a represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.~~

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~

~~Real Power output (P):~~

~~Eq. (151)~~ $\cancel{P = GEN_{Synch\_nameplate} \times pf}$

$\cancel{P = 903\,MVA \times 0.85}$

$\cancel{P = 767.6\,MW}$

~~Reactive Power output (Q):~~

~~Eq. (152)~~ $\cancel{Q = 120\% \times P}$

$\cancel{Q = 1.20 \times 767.6\,MW}$

$\cancel{Q = 921.12\,Mvar}$

~~Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:~~

~~Eq. (153)~~ $\cancel{V_{bus} = 0.85\,p.u. \times V_{nom}}$

$\cancel{V_{bus} = 0.85 \times 345\,kV}$

$\cancel{V_{bus} = 293.25\,kV}$

~~Apparent power (S):~~

~~Eq. (154)~~ $\cancel{S = P_{Synch\_reported} + jQ}$

~~Example Calculations: Options 15a and 16a~~

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

~~Primary current (I_{pri}):~~

~~Eq. (155)~~ $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

~~Secondary current (I_{sec}):~~

~~Eq. (156)~~ $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\ A$$

~~To satisfy the 115% margin in Options 15a and 15b:~~

~~Eq. (157)~~ $$I_{sec\ limit} > I_{sec} \times 115\%$$

$$I_{sec\ limit} > 5.701\angle -52.8°\ A \times 1.15$$

$$I_{sec\ limit} > 6.56\angle -52.8°\ A$$

~~Example Calculations: Options 15b and 16b~~

~~Options 15b and 16b represent the calculation for a synchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 15b represents applying a phase time overcurrent relay (51) or Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer. Option 16b represents applying a phase directional time overcurrent relay or Phase directional overcurrent supervisory elements (67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – directional toward the Transmission system– installed on the high-side of the GSU.~~

~~This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.~~

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

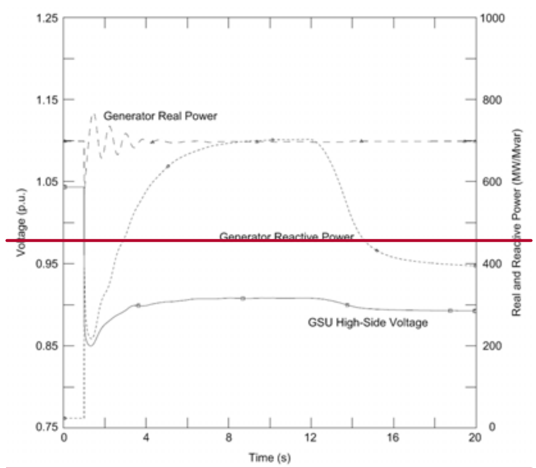
~~In this simulation the following values are derived:~~

$$\cancel{Q = 703.6\ Mvar}$$

$$\cancel{V_{bus} = 0.908 \times V_{nom} = 313.3\ kV}$$

~~The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:~~

$$\cancel{P_{reported} = 700.0\ MW}$$



~~Apparent power (S):~~

~~Eq. (158)~~ $\cancel{S = P_{synch\_reported} + jQ}$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

~~Primary current (I_{pri}):~~

Eq. (159) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

~~Secondary current (I_{sec}):~~

Eq. (160) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\ A$$

~~To satisfy the 115% margin in Options 15b and 16b:~~

Eq. (161) $$I_{sec\,limit} > I_{sec} \times 115\%$$

$$I_{sec\,limit} > 4.578\angle -45.1°\ A \times 1.15$$

$$I_{sec\,limit} > 5.265\angle -45.1°\ A$$

Example Calculations: Option 17

~~Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.~~

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

~~Eq. (162)~~ $\cancel{P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf}$

Eq. (175) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

~~Eq. (163)~~ $\cancel{Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)}$

Eq. (176) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

~~Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):~~

~~Eq. (164)~~ $\cancel{V_{bus} = 1.0\ p.u. \times V_{nom}}$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

~~Eq. (165)~~ $\cancel{S = P + jQ}$

Eq. (178) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option 17

Primary impedance (Z_{pri}):

Eq. (~~166~~179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, and then the maximum allowable impedance reach is:

Eq. (~~169~~182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

Example Calculations: Option 17

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation Elements that connect a~~ relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~ .

Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~170~~183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Options 18 and 19

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high-side~~line nominal voltage (V_{bus}):

Eq. (~~172~~185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (~~173~~186) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 18 and 19

$$I_{\sec limit} > 3.675\angle -39.2° \, A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2° \, A$$

End of calculations

Rationale~~:~~

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

Rationale for R1~~:~~

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1
Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite Standard

- None

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

This Implementation Plan supersedes and retires the *Implementation Plan PRC-025-1 – Generator Relay Loadability*[1] such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. In drafting this Implementation Plan, the PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the phased-in implementation dates for PRC-025-1. The first U.S. phased-in implementation date for PRC-025-1 of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. phased-in implementation date for PRC-025-1 of October 1, 2021 applies to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities,
- The proposed revisions to Options 14b, 15b, and 16b may give reason for entities to re-evaluate their settings for load-responsive protective relays,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[1] http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_(Clean).pdf

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the later of October 1, 2019 or 12 months after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 – Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the later of October 1, 2021 or 36 months after the effective date of Reliability Standard PRC-025-2, except as noted for the Table 1 Relay Loadability Evaluation Criteria Options listed below

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	**Application and Relay Type**	**Implementation Date**
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V-R – voltage-restrained)[2]	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

[2] Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

None

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1

~~Requested Approvals~~

Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested ~~Retirements~~Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite ~~Approvals~~Standard

- None~~.~~

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

~~The~~This Implementation Plan supersedes and retires the *Implementation Plan PRC-025-1 – Generator Relay Loadability*[1] such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. In drafting this Implementation Plan, the PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the ~~version one enforcement~~phased-in implementation dates~~.~~ for PRC-025-1. The first U.S. ~~enforcement~~phased-in implementation date for PRC-025-1 of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. ~~enforcement~~phased-in implementation date for PRC-025-1 of October 1, 2021 applies to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities~~.~~,
- The proposed revisions to Options ~~14a,~~ 14b, ~~15a,~~ 15b, ~~16a, 16b, 17, 18,~~ and ~~19~~16b may give reason for entities to re-evaluate their settings for load-responsive protective relays~~.~~,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[1] http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_(Clean).pdf

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the later of October 1, 2019 or 12 months after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 – Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the later of October 1, 2021 or 36 months after the effective date of Reliability Standard PRC-025-2, except as noted for the Table 1 Relay Loadability Evaluation Criteria Options listed below

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	**Application and Relay Type**	**Implementation Date**
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V-R – voltage-restrained)[2]	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

[2] Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

None~~.~~

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Unofficial Comment Form

Project 2016-04 Modifications to PRC-025-1

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **PRC-025-2 – Generator Relay Loadability**. Comments must be submitted by **8 p.m. Eastern, Wednesday, December 13, 2017.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Scott Barfield-McGinnis (via email), or at 404-446-9689.

Background Information

Reliability Standard PRC-025-1 (Generator Relay Loadability), which was approved by the Federal Energy Regulatory Commission in Order No. 799 issued on July 17, 2014, became effective on October 1, 2014. Under the phased implementation plan, applicable entities have between five and seven years to become compliant with the standard depending on the scope of work required by the Generator Owner. In the course of implementing the standard, issues have been identified for specific Facility applications and load-responsive protective relays.

The revised PRC-025-2 standards addresses the concerns outlined in the Standards Authorization Request accepted by the Standards Committee on September 14, 2016. The revisions in this draft are clarifying based on industry comment; however, the standard drafting team (SDT) is proposing a revised Implementation Plan to address concerns raised in the comments and informal outreach.

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-04 Modifications to PRC-025-1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. 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 Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for 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 Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

The FERC 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 for PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF Justifications for PRC-025-1, R1	
Proposed VRF	**High**
Guideline 4- Consistency with NERC Definitions of VRFs	The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

VSLs for PRC-025-2, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications for PRC-025-2, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.

VSL Justifications for PRC-025-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.

VSL Justifications for PRC-025-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Questions

1. The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

   ☐ Yes

   ☐ No

   Comments:

2. If you have any other comments on the Standard or documents, please provide them here:

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications~~Violation Risk Factor and Violation Severity Level Justifications~~

Project 2016-04 Modifications to PRC-025-~~2 – Generator Relay Loadability~~1

~~Violation Risk Factor and Violation Severity Level Justifications~~

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in~~: PRC-025 – Generator Relay Loadability. Note that no Requirement, Measure,~~ [Project Number and Name or ~~VRF/VSL changes have been made in this proposed PRC-025-2 Reliability~~ Standard~~.~~

Number]. Each ~~primary~~ requirement is assigned a VRF and a ~~set of one or more VSLs~~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~~Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

~~The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.~~

NERC Criteria ~~–~~for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to ~~bulk electric system~~Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the ~~bulk electric system~~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~~Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the ~~bulk electric system~~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~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk electric system.~~Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to ~~bulk electric system~~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~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk electric system~~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~~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~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk electric system~~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~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk electric system. A planning requirement that is administrative in nature.~~Bulk Electric System.

FERC ~~Violation Risk Factor Guidelines~~

~~The SDT also considered consistency with the FERC Violation Risk Factor~~ **Guidelines for** ~~setting VRFs:~~[1] **Violation Risk Factors**

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

~~The Commission~~ FERC seeks to ensure that ~~Violation Risk Factors~~VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- 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

~~[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").~~
~~[2] Id. at footnote 15.~~

- Appropriate use of transmission loading relief.

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

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

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

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

NERC Criteria ~~–~~for 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**~~VSLs should be based on ~~**the guidelines**~~NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
~~Missing a minor element (or a small percentage) of the required performance~~ The performance or product measured ~~has significant value as it~~ almost meets the full intent of the requirement.	~~Missing at least one significant element (or a moderate percentage) of the required performance.~~ The performance or product measured ~~still has significant value in meeting the~~ meets the majority of the intent of the requirement.	~~Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component.~~ The performance or product ~~has limited value in meeting the~~ measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	~~Missing most or all of the significant elements (or a significant percentage) of the required performance.~~ The performance or product measured does not substantively meet the intent of the requirement ~~or the product delivered cannot be used in meeting the intent of the requirement.~~.

FERC Order of Violation Severity Levels

~~FERC's~~The FERC 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~~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 and VSL Justifications**~~

VRF Justifications ~~–~~for PRC-025-~~2~~1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.

VRF Justifications ~~-~~for PRC-025-~~2~~1, R1	
Proposed VRF	**High**
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

~~Proposed~~ VSLs for PRC-025-2, R1				
~~R1~~	**Lower**	**Moderate**	**High**	**Severe**
~~R1~~	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

Deleted Cells

VSL Justifications –for PRC-025-2, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.

VSL Justifications –for PRC-025-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be “Severe” in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.

VSL Justifications ~~–~~for PRC-025-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Standards Announcement

Reminder

Project 2016-04 Modifications to PRC-025-1

Additional Ballot and Non-binding Poll Open through December 13, 2017

Now Available

An additional ballot for **PRC-025-2 – Generator Relay Loadability** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Wednesday, December 13, 2017.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Balloting

Members of the ballot pools associated with this project may log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience any difficulties in navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Note: If a member cast a vote in the previous ballot, that vote will not carry over to this additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in this ballot. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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

Standards Announcement

Project Project 2016-04 Modifications to PRC-025-1

Formal Comment Period Open through December 13, 2017

Now Available

A 45-day formal comment period for **PRC-025-2 – Generator Relay Loadability**, is open through **8 p.m. Eastern, Wednesday, December 13, 2017**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience any difficulties navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **December 4-13, 2017**.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/114)
Ballot Name: 2016-04 Modifications to PRC-025-1 PRC-025-2 AB 2 ST
Voting Start Date: 12/4/2017 12:01:00 AM
Voting End Date: 12/14/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 255
Total Ballot Pool: 312
Quorum: 81.73
Weighted Segment Value: 88.25

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	61	0.938	4	0.062	0	8	8
Segment: 2	4	0.2	2	0.2	0	0	0	1	1
Segment: 3	73	1	49	0.845	9	0.155	0	4	11
Segment: 4	17	1	8	0.727	3	0.273	0	0	6
Segment: 5	74	1	43	0.86	7	0.14	0	6	18
Segment: 6	50	1	32	0.889	4	0.111	0	3	11
Segment: 7	2	0.1	1	0.1	0	0	0	0	1
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.6	6	0.6	0	0	0	0	1
Totals:	312	6.3	206	5.559	27	0.741	0	22	57

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Third-Party Comments
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Memphis Light, Gas and Water Division	Allan Long		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		None	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	AEP	Aaron Austin		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
3	Rutherford EMC	Tom Haire		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		None	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
5	Arkansas Electric Cooperative Corporation	Moses Harris		None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
5	Exelon	Ruth Miller		Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Third-Party Comments
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Exelon	Becky Webb		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jim Flucke	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		None	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Showing 1 to 312 of 312 entries

Previous 1 Next

BALLOT RESULTS

Ballot Name: 2016-04 Modifications to PRC-025-1 PRC-025-2 AB 2 NB
Voting Start Date: 12/4/2017 12:01:00 AM
Voting End Date: 12/14/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 234
Total Ballot Pool: 297
Quorum: 78.79
Weighted Segment Value: 87.78

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	77	1	45	0.938	3	0.063	19	10
Segment: 2	4	0.2	2	0.2	0	0	1	1
Segment: 3	69	1	38	0.844	7	0.156	13	11
Segment: 4	17	1	7	0.7	3	0.3	1	6
Segment: 5	70	1	32	0.842	6	0.158	12	20
Segment: 6	47	1	23	0.885	3	0.115	8	13
Segment: 7	2	0.1	1	0.1	0	0	0	1
Segment: 8	3	0.3	3	0.3	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0
Segment: 10	7	0.6	6	0.6	0	0	0	1

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Totals:	297	6.3	158	5.509	22	0.791	54	63

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	American Transmission Company, LLC	Douglas Johnson		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Negative	Comments Submitted
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Memphis Light, Gas and Water Division	Allan Long		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		None	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		None	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Abstain	N/A
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		None	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Elizabeth Axson		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	AEP	Aaron Austin		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Brandon McCormick	Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
3	Rutherford EMC	Tom Haire		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Rudy Navarro		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		None	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Abstain	N/A
5	Acciona Energy North America	George Brown		Negative	Comments Submitted
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Basin Electric Power Cooperative	Mike Kraft		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Francis Halpin		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Abstain	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy	Jamie Prater		Negative	Comments Submitted
5	Exelon	Ruth Miller		Abstain	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Randy Crissman		Affirmative	N/A
5	NextEra Energy	Allen Schriver		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Abstain	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jim Flucke	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		None	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		None	N/A

Showing 1 to 297 of 297 entries

Previous 1 Next

Standards Announcement

Project Project 2016-04 Modifications to PRC-025-1

Formal Comment Period Open through December 13, 2017

Now Available

A 45-day formal comment period for **PRC-025-2 – Generator Relay Loadability**, is open through **8 p.m. Eastern, Wednesday, December 13, 2017**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience any difficulties navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **December 4-13, 2017**.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

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

Comment Report

Project Name:	2016-04 Modifications to PRC-025-1 | PRC-025-2
Comment Period Start Date:	10/30/2017
Comment Period End Date:	12/14/2017
Associated Ballots:	2016-04 Modifications to PRC-025-1 PRC-025-2 AB 2 ST

There were 39 sets of responses, including comments from approximately 126 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

2. If you have any other comments on the Standard or documents, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric	1	RF

						Cooperative, Inc.		
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	5	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC

					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Lower Colorado River Authority	Michael Shaw	1		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC

Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					J. Scott Williams	City of Utilities of Springfield, MO	1,4	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE

PPL - Louisville Gas and Electric Co.	Shelby Wade	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC

1. The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods.	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Allow 36 months instead of 24 months for the added option per this revision. Generators with 24 month outage schedules will need the additional time, especially nuclear plants.	
Likes 0	
Dislikes 0	
Response	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	No
Document Name	
Comment	
Recommend providing the same 60-month and 84-month implemenation preiods no matter what aype of protective device, to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The SDT should provide the same full 60 and 84 month phased-in implementation from the first effective date of PRC-025-2 for any protective devices that apply to footnote 1, of proposed PRC-025-2 (1 Relays include low voltage protection devices that have adjustable settings). The SDT must allow entities appropriate time to adjust to changes in the NERC standard.

Likes 0	
Dislikes 0	

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	No
Document Name	

Comment

Comments submitted as part of ACES comments

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

We appreciate the SDT's inclusion of a transition period between implementation plans for this standard. However, we find the phased-in approach based on varying options of relay loadability evaluation criteria confusing. For load responsive protective relays that are currently subject to the standard, the current implementation plan could possibly supersede the proposed implementation plan. We believe a phased-in implementation period should clearly begin on the effective date of the proposed standard and independent of specific relay loadability evaluation criteria. If an entity determines that replacement or removal of the relay is not necessary, then the entity should have 24 months after the standard's effective date to make other associated changes. However, if the entity determines relay replacement or removal is necessary, then the entity should have 48 months after the standard's effective date for procurement and installation of the new relay. With the inclusion of the element 50 relay in this proposed standard, the SDT's 60-month and 84-month respective implementation period is tolerable.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BHC feels the IP is reasonable.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes this most recently proposed Implementation Plan is reasonable.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Adkins, City of Leesburg, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	
Support Comments submitted by the MRO NERC Standards Review Forum (NSRF)	
Likes 0	
Dislikes 0	
Response	

2. If you have any other comments on the Standard or documents, please provide them here.

David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
For figure 2, identify that busses B, C, and D and their interconnecting lines as 'the transmission system' for clarity. We believe that this will help clarify that only reverse-looking or non-directional elements are within PRC-025 scope.	
Likes 0	
Dislikes 0	
Response	

George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	

First, the PRC-025 Standard Drafting Team (SDT) has done an excellent job of addressing application 5B as it relates to dispersed power producing resources. However, I still have a concern how PRC-025 is applied to other equipment at the generation asset. My concern is in relation to equipment that is not designed to operate at 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor and this equipment is at a facility that was built prior to PRC-025 becoming effective/enforceable. My specific concern relates to the following Applications and Options in Attachment 1, Table 1.

- Application: Relays installed on generator only (including inverter-based installations).
- Options: 10, 11 & 12

- Application: Relays installed on the high that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. (except that Elements may also supply generating plant loads.) – connected to asynchronous generators only (including inverter-based installations).
- Options: 17, 18 & 19

For example, let's say that a dispersed power producing resource's main power transformer (MPT) is only rated to run continuously at 110% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor or what is better known as a original equipment manufacturer damage curve. If an entity was to set its respective protection systems for that MPT to ≥ 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor then the MPT is no longer properly protected, has become a safety issue for personnel that work around the MPT and at risk of catastrophic failure.

I would like to recommend the SDT add similar language as drafted for application 5B to Options 10, 11, 12, 17, 18 & 19. Perhaps, even taking it a step further and adding in some sort of “grandfathering” language, so that facilities that are connected/constructed after the effective/enforcement of PRC-025 would be designed to meet the 130%, while facilities built prior can have their protection systems set to the maximum allowable level based on the equipment installed at the facility.

Essentially, there is potential that many dispersed power producing resources will have equipment throughout the site that will not allow them to set protection systems to ≥ 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor while still providing adequate protection to the equipment necessary for the safe and reliable operation of the facility.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Adkins, City of Leesburg, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	
Document Name	

Comment

It would seem that item number 5 of the SAR was not completed. For example, the setting criteria for Table 1 still has language such as “…shall be set less than the calculated impedance derived from 115% of: ….”

From item number 5 of the SAR, **“Clarify that multiple methods/curve types are acceptable so long as the applied protection *does not trip* the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non - mho relay characteristics and other schemes in which the relay’s initial measurement may detect a condition (e.g., may “pickup”) but the relay is blocked from operating.”**

Since the Table 1 descriptors still refer to an “impedance element setting”, the issue still exists despite removing the term “Pickup”, which was only part of what was needed. Using the phrase “shall not trip” rather than the phrase “shall be set” in the Table 1 Setting Criteria will accomplish the goal of item number 5. Due to the SAR not being complete, FMPA is casting a negative ballot.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	

Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Attachment 1 states that relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner. This does not account for the scenario when the Generator Owner (GO) does not provide accurate capability data to the Transmission Planner (TP). Texas RE suggests it would be more effective to base the Real Power capability on calculations used for the determination of Facility Ratings or the Real Power capability verification performed for MOD-025-2.

As previously requested, Texas RE asks the SDT consider providing a justification of the “Long Term Planning” time horizon as it has a significant impact on Penalty calculations. The phrase “shall apply settings” is indicative of a Real-time or near Real-time action. While planning activities have to recognize proposed settings (and reflect current setting for those relays not subject to change), ultimately the setting occurs in a much shorter time horizon than “Long-term Planning”.

Texas RE also noticed the following:

- In the redline version, the header still has “-1” throughout some of the change management documents of the Standard. Texas RE did notice the header was changed to PRC-025-2 in the clean version.
- Section “C: Compliance 1.3 Compliance Monitoring and Assessment Processes” appears to not follow the template for Results Based Standards. This version lists out the various compliance monitoring processes, whereas the template states: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.
- The Violation Severity Level table does not follow the template for Results Based Standards.
- The introduction in Attachment 1, references “3.2 Facilities”. Facilities are listed in section 4.2 of the standard.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

1. We believe a performance-based criteria could be established for the Violation Severity Levels (VSLs) for this standard, similar to what is present for NERC Reliability Standard PRC-005-6. In that standard, the severity is based on a specific percentage of Components the applicable entity failed to maintain in accordance with minimum maintenance activities and maximum maintenance intervals. In this standard, a severe VSL is assessed when the entity fails to apply the required settings for any one load responsive protective relay. We recommend a gradated approach based on the percentage of load-responsive protective relays where the entity failed to apply settings. This would complement the list of load-responsive protective relays identified as requested evidence in the standard’s RSAW.
2. We ask the SDT to include hyperlinks for documents referenced as footnotes. The presence of multi-lined web addresses can inadvertently include extra spaces that corrupts or disables the link.
3. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	
Document Name	

Comment

We appreciate the drafting team's consideration of our comments submitted on PRC-025-2, Draft 1. We believe the drafting team's response to our comment under Question 12 should be added as a footnote to Table 1. Specifically, consider adding the following as a clarifying footnote to Table 1: "The "gross MW capability reported to the Transmission Planner" is based upon NERC Reliability Standard MOD-025-2. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement."

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	
Document Name	

Comment

Support Comments submitted by the MRO NERC Standards Review Forum (NSRF)

Likes 0	
Dislikes 0	

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment

Comments were submitted as part of ACES Commnets.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	
Document Name	
Comment	
Question for drafting team: “If a line connecting the GSU transformer(s) to the Transmission system has a load (that is not generating plant load) tapped to it, would Options 14, 15, or 16 apply at the remote end of the line? Would it apply at the high-side of the GSU transformer(s)? If the answer to both questions above is ‘no,’ then, if there are two lines connecting the GSU transformer(s) to the Transmission system, and one line has a load (that is not generating plant load) tapped to it, would Options 14, 15, or 16 apply at the high-side of the GSU transformer(s)?”	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	
Document Name	
Comment	
In the previous request for comments Exelon requested that the Project 2016-04 SDT evaluate the proposed fault detector settings associated with pilot wire communication systems. Specifically, Exelon stated in the response to Question 2 that "[c]alculations performed to calculate the settings for these type of relays show that the settings are very close to the 3-phase fault current contributed from the generator in cases where sub-transient reactance of the machine is at a high value. This will compromise the protection scheme because the changes proposed will make the protection scheme very insensitive. In case of a high resistance phase-to-ground fault, the protection scheme will not pick up the fault at the generator end. In some extreme cases, the fault detector relay (67 or 50), if set according to the current draft PRC-025 guidelines, may have to depend on the field forcing provided by	

the Automatic Voltage Regulator (AVR) before the fault current reaches the setpoint. This will induce unnecessary delays in the protective action and may cause more damage to the BES element."

The SDT response to Exelon's comment was that this issue was "beyond the scope of the drafting team's work to revise PRC-025-1 as described in the SAR" and that an entity might have to "employ alternative protection schemes to achieve the loadability requirements and fault protection." Exelon does not agree that this is outside the scope of the SAR given consideration item (2) in the SAR specifically states that this project is to address the inclusion or exclusion of the 50 element.

To address our concerns, Exelon requests the following changes:

1. The fault detector relays used in communication systems should be deleted from the scope of this standard because these particular relays are subject to misoperation only when the communication system has failed and there is a concurrent disturbance on the grid.
2. If there is any issue with a communication system and if the whole pilot protection scheme becomes a simple overcurrent relay, that condition is alarmed. Therefore, this condition would only exist for a short duration. To fix this condition the SDT can add a requirement to remedy this condition within a certain timeframe (e.g., correct condition within three months) and if not resolved then setpoints of 67 or 50 should be raised.
3. If the SDT still wants to retain these relays within the scope, then Exelon requests that the existing setting criteria should be modified as follows:
    i. “Minimum of the criteria 15a (or 15b) or 25% of the current contribution from the generator using a pre-fault voltage of 1.0 pu, generator sub-transient unsaturated reactance, and the main power transformer positive sequence reactance."

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	
Document Name	

Comment

By adding the phrase “except that” to “Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.” in multiple places throughout the document, ambiguity is increased rather than decreased. LKE suggests replacing these instances with full, clearly worded sentences.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	
Document Name	PRC-025 modifications drawing.docx

Comment

Xcel Energy has concerns that the changes to the "Application" column for Options 7a-7c, 8a-8c, and 9a-9c are somewhat misleading and the description is inconsistent with Figure 5. We do acknowledge that this is partially a carryover issue from PRC-025-1.

The "Application" column for options 7, 8 & 9 describe "Relays installed on the generator side of the Generator step-up transformer..." Figure 5 shows that the current transformers for the load dependent relays to which options 7-9 are applicable are actually applied on the generator or the generator breaker and not specifically on the low side of the GSU. Note that many microprocessor based generator protection relays allow you to select the signal source for the current input to the 21 function such that either neutral or line side current transformers may be used for the current signal input to the 21 device associated with the generator. In other words, not all generator load dependent relays are fed neutral side current transformers. From this perspective, it would be unclear whether the entity should be using option 1a-1c or option 7a-7c for evaluating the loadability of the 21 function or options 2a-2c or option 8z-8c for the 50/51 functions.

Note that on Figure 5, the location of the generator breaker relative to the generator bus tap to the UAT is incorrect for most typical applicactions. In most applications when a generator breaker is provided, it will be on the generator bus between the generator and the bus tap to the UAT so that the UAT remains in service from the GSU when the generator breaker is open and the generator is offline. There would be operational value in a generator breaker between the UAT tap and GSU LV winding as shown in Figure 5. By moving the location of the generator breaker to the correct location between the generator and UAT bus tap on Figure 5, all inconsistency would be elimated and would greatly improve the clarity of the differences between options 1 vs. 7 and 2 vs. 8. See attached file for markup of Figure 5.

Based on the criteria included in the "settings criteria" colum for options 1, 2, 7 & 8, the key difference to use when determining which option to use is dependent on if the current transformer feeding the load dependent relay includes measurement of current flowing to the UAT in addition to that flowing to the LV winding of the GSU from the generator.

Beyond the above issue with the description clarity, we also have the following technical concerns with options 7 & 8 vs. options 1 & 2:

1. In many instances, in addition to the unit connected auxiliary transformer, a plant also likely has a 100% power capable system connected auxiliary transformer. In this case, the amount of power the plant would be capable of putting out would, to the system, be greater and the settings of any load dependent relay when the plant is fed from the system connected aus, should be based on that capability and calculated per option 1 or 2 and not for the lower value of aggregate power as allowed by option 7 or 8 - regardless of the location of the CT used to feed the load dependent relay. If an entity's reported max gross MW value is based on the gross output when fed from the system connected auxiliary source, then the entity should have to use option 1 or 2 regardless of the configuration of the current transformer relative to the unit connected auxiliary transformer. Option 7 or 8 should only be allowed if the max gross MW reported is based on the reduced output available when the unit is receiving auxiliary power from the unit connected auxiliary transformer.
2. The differences in determining real power between options 1 and 2 vs. 7 adn 8 is understandable, but it is unclear why the reactive power used in option 7 & 8 are calculated differently than that used in options 1 & 2. What is the technical justification for the difference? The response of the machine to depressed grid voltages and field forcing capability will be the same regardless of where the load dependent relay current transformer is located relative to the aux power tap. Using a reduced value for field forcing MVAR based on aggregate MW output rather than a MW value based strictly on nameplate MVA and rated pf does not seem justified.

Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
The Exclusions section should also exclude the following protection system based on footnote 1 in the Applicability Section: Low voltage protection devices that do not have adjustable settings.	
Likes 0	
Dislikes 0	

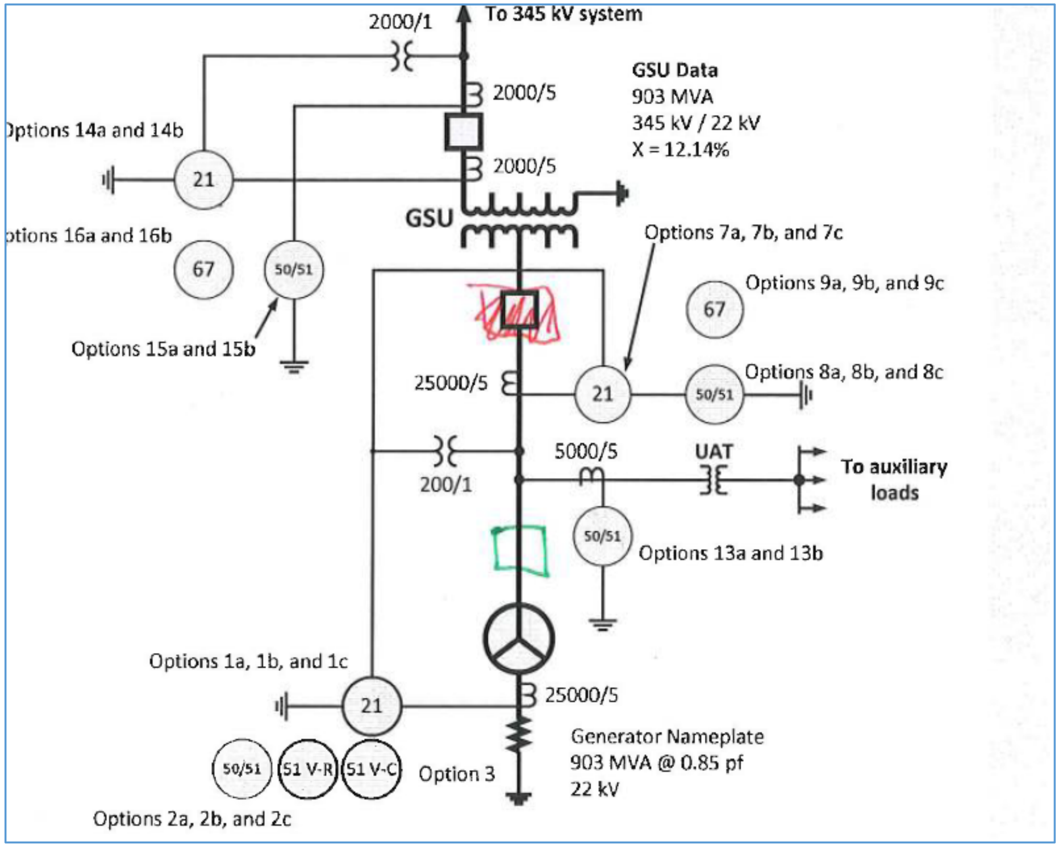
Response	
Tom Haire - Rutherford EMC - 3	
Answer	
Document Name	
Comment	
Section 4.2.5 should have a minimum threshhold.	
Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	

Supplemental to comments | Xcel Energy

Project 2016-04 Modifications to PRC-025-1



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2016-04 Modifications to PRC-025-1 | PRC-025-2
Comment Period Start Date: 10/30/2017
Comment Period End Date: 12/14/2017

There were 39 sets of responses, including comments from approximately 126 different people from approximately 93 companies representing the 10 Industry Segments as shown in the table on the following pages.

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director, Standards and Education Howard Gugel (via email) or at (404) 446-9693.

Summary Consideration
The standard received overwhelming support at 88.25% approval, a seven point increase over the initial ballot. The increase in approval is attributed to the changes the drafting team made to the Implementation Plan. Namely, allowing a phased-in implementation of 60/84 months for the 50 relay element and 24/48 for other revisions.

A few comments expressed concern that a phased-in approach to the Implementation Plan is confusing and should be based solely off of the regulatory approval date. The drafting team did not agree with commenters on their rationale for increases or changes to the Implementation Plan or that the phased-in approach was confusing.

Several commenters suggested excellent non-substantive tweaks to the standard while other raised technical questions. The drafting team addressed the following non-substantive revisions:

1. Added a demarcation line to the figures to highlight where the Transmission system began.
2. Updated the Compliance section of the standard to the current template language.
3. Updated the Violation Severity Level (VSL) table to the current template by removing the Violation Risk Factor (VRF) and Time Horizon columns.
4. Corrected the Attachment 1 reference to Facilities from 3.2 to 4.2.

Technical issues included the following:

1. One concern about the 130% setting for asynchronous resources at the generator step-up transformer. The drafting team noted that protective relays that detect overloads are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions are exempt from the standard and should be employed where thermal protection of equipment is a concern. The expectation for loadings less than 130% would be for overloading conditions rather than fault conditions.
2. A concern that the drafting team had not met the objective of item #5 of the Standards Authorization Request. The drafting team disagreed and believes it has met the spirit of item #5 by removing the term “Pick Up,” which aligns with the standard’s purpose to set relays a level to prevent unnecessary tripping of generators.
3. One comment suggested using gross Real Power as determined by Facility ratings. The drafting team noted that Mega-Watt (MW) value (gross Real Power capability) reported to the Transmission Planner under PRC-025-2 is a minimum criteria for the determination of settings. Requiring the use of Facility ratings may not be indicative of the generator capability and could affect the sensitivity of the protection settings.
4. Another comment requested the Requirement R1 VSL to be based on a percentage of missed settings rather than per relay basis. The drafting team noted that the construction of the Requirement does not lend itself to using a graduated VSL.
5. Although the standard bases its calculations on the MOD-025 standard (generator verification) for gross MW value reported to the Transmission Planner as a minimum value, the drafting team was not inclined to add that reference to the standard.
6. One comment questioned how an interconnecting line would be handled if it were tapped with load. The drafting team responded that the Applicability section of the standard would determine whether the line was applicable to PRC-025 or not. The line could be applicable to PRC-023 (Transmission Loadability), however, in any case the entity should use good engineering judgement if a line is not applicable to the standard and is affected by generator output (i.e., loadability).
7. Another single comment illustrated a specific protection scheme and requested a revision to allow an exception to the condition. The drafting team did not agree an exception was appropriate and noted that an entity may be required to remove or replace relays in order to meet the requirement of the standard.

Questions

1. The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

2. If you have any other comments on the Standard or documents, please provide them here.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	5	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Lower Colorado River Authority	Michael Shaw	1		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					J. Scott Williams	City of Utilities of Springfield, MO	1,4	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC

Question 1	
1. ***The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods*.**	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Allow 36 months instead of 24 months for the added option per this revision. Generators with 24 month outage schedules will need the additional time, especially nuclear plants.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The added Option 5b provided an additional means to address loadability on asynchronous resources (not nuclear) and is not expected to create significant work for the entity. Therefore, the drafting team is keeping the current implementation phased-in periods at 24 and 48 months from regulatory approval for setting changes or equipment retirement/replacement, respectively. The 50 element, which could impact nuclear facilities, has been provided a 60 and 84 month implementation period for setting changes or equipment retirement/replacement, respectively.	
Theresa Allard - Minnkota Power Cooperative Inc. - 1	
Answer	No
Document Name	

Question 1	
Comment	
Recommend providing the same 60-month and 84-month implemenation preiods no matter what aype of protective device, to avoid confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team extended the time periods for implementation to address components of the standard that were revised based on comments from the initial posting and subsequent outreach. The relays that were not affected by the revisions will not be phased-in any earlier than the original effective dates of October 1, 2019 for setting changes and October 1, 2021 for removal/replacement.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The SDT should provide the same full 60 and 84 month phased-in implementation from the first effective date of PRC-025-2 for any protective devices that apply to footnote 1, of proposed PRC-025-2 (1 Relays include low voltage protection devices that have adjustable settings). The SDT must allow entities appropriate time to adjust to changes in the NERC standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Footnote 1 has not introduced any new relays into the standard and was added only to provide clarification for low voltage applications that meet the applicability of the standard.	
William Hutchison - Southern Illinois Power Cooperative - 1	

Question 1	
Answer	No
Document Name	
Comment	
Comments submitted as part of ACES comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to ACES' comment(s).	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We appreciate the SDT's inclusion of a transition period between implementation plans for this standard. However, we find the phased-in approach based on varying options of relay loadability evaluation criteria confusing. For load-responsive protective relays that are currently subject to the standard, the current implementation plan could possibly supersede the proposed implementation plan. We believe a phased-in implementation period should clearly begin on the effective date of the proposed standard and independent of specific relay loadability evaluation criteria. If an entity determines that replacement or removal of the relay is not necessary, then the entity should have 24 months after the standard's effective date to make other associated changes. However, if the entity determines relay replacement or removal is necessary, then the entity should have 48 months after the standard's effective date for procurement and installation of the new relay. With the inclusion of the element 50 relay in this proposed standard, the SDT's 60-month and 84-month respective implementation period is tolerable.	
Likes 0	
Dislikes 0	

Question 1	
Response	
Thank you for your comment. The drafting team extended the time periods for implementation to address components of the standard that were revised based on comments from the initial posting and subsequent outreach. The relays that were not affected by the revisions will not be phased-in any earlier than the original effective dates of October 1, 2019 for setting changes and October 1, 2021 for removal/replacement.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BHC feels the IP is reasonable.	
Likes 0	
Dislikes 0	
Response	

Question 1	
Thank you for your comment.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes this most recently proposed Implementation Plan is reasonable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Question 1	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	

Question 1	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Adkins, City of Leesburg, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 1	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Question 1	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	
Support Comments submitted by the MRO NERC Standards Review Forum (NSRF)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to the MRO NSRF.	

Question 2	
2. *If you have any other comments on the Standard or documents, please provide them here*.	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
For figure 2, identify that busses B, C, and D and their interconnecting lines as 'the transmission system' for clarity. We believe that this will help clarify that only reverse-looking or non-directional elements are within PRC-025 scope.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has updated Figures 1, 2, and 3 with a demarcation line labeled "Transmission System" for added clarity.	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
First, the PRC-025 Standard Drafting Team (SDT) has done an excellent job of addressing application 5B as it relates to dispersed power producing resources. However, I still have a concern how PRC-025 is applied to other equipment at the generation asset. My concern is in relation to equipment that is not designed to operate at 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor and this equipment is at a facility that was built prior to PRC-025 becoming effective/enforceable. My specific concern relates to the following Applications and Options in Attachment 1, Table 1.	

Question 2

- Application: Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations).
- Options: 10, 11 & 12
- Application: Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. (except that Elements may also supply generating plant loads.) – connected to asynchronous generators only (including inverter-based installations).
- Options: 17, 18 & 19

For example, let's say that a dispersed power producing resource's main power transformer (MPT) is only rated to run continuously at 110% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor or what is better known as a original equipment manufacturer damage curve. If an entity was to set its respective protection systems for that MPT to ≥ 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor then the MPT is no longer properly protected, has become a safety issue for personnel that work around the MPT and at risk of catastrophic failure.

I would like to recommend the SDT add similar language as drafted for application 5B to Options 10, 11, 12, 17, 18 & 19. Perhaps, even taking it a step further and adding in some sort of "grandfathering" language, so that facilities that are connected/constructed after the effective/enforcement of PRC-025 would be designed to meet the 130%, while facilities built prior can have their protection systems set to the maximum allowable level based on the equipment installed at the facility.

Essentially, there is potential that many dispersed power producing resources will have equipment throughout the site that will not allow them to set protection systems to ≥ 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor while still providing adequate protection to the equipment necessary for the safe and reliable operation of the facility.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team does not agree that alternatives for Options 10, 11, 12, 17, 18, and 19 in Table 1 need to be included to address equipment that is not installed and set to operate at 130% of the calculated current based on the maximum

Question 2	
aggregate nameplate MVA. Protective relays that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions are exempt from the standard and should be employed where thermal protection of equipment is a concern. The expectation for loadings less than 130% would be for overloading conditions rather than fault conditions.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Adkins, City of Leesburg, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	
It would seem that item number 5 of the SAR was not completed. For example, the setting criteria for Table 1 still has language such as "…shall be set less than the calculated impedance derived from 115% of: …." From item number 5 of the SAR, **"Clarify that multiple methods/curve types are acceptable so long as the applied protection *does not trip* the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating."** Since the Table 1 descriptors still refer to an "impedance element setting", the issue still exists despite removing the term "Pickup", which was only part of what was needed. Using the phrase "shall not trip" rather than the phrase "shall be set" in the Table 1 Setting Criteria will accomplish the goal of item number 5. Due to the SAR not being complete, FMPA is casting a negative ballot.	
Likes 0	
Dislikes 0	
Response	

Question 2	
Thank you for your comment. The Standards Authorization Request (SAR) has been met by eliminating the term "Pick Up," which aligns with the standard's purpose to set relays to a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. The standard encourages entities to reduce the reach of their relays, which is originally what initiated the standards PRC-023 and PRC-025 as well as improving loadability during depressed voltages. If an entity applies blinders to the existing relays, implementation of lenticular characteristic relays, or implementation of load encroachment characteristics, then the entity will need to demonstrate how it achieves the intent to not trip for the conditions described in the standard. See PRC-025-2 Application Guidelines Section "Phase Distance Relay – Directional Toward Transmission System (e.g., 21)" for more information.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	
N/A	

Question 2	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Attachment 1 states that relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner. This does not account for the scenario when the Generator Owner (GO) does not provide accurate capability data to the Transmission Planner (TP). Texas RE suggests it would be more effective to base the Real Power capability on calculations used for the determination of Facility Ratings or the Real Power capability verification performed for MOD-025-2.

As previously requested, Texas RE asks the SDT consider providing a justification of the "Long Term Planning" time horizon as it has a significant impact on Penalty calculations. The phrase "shall apply settings" is indicative of a Real-time or near Real-time action. While planning activities have to recognize proposed settings (and reflect current setting for those relays not subject to change), ultimately the setting occurs in a much shorter time horizon than "Long-term Planning".

Texas RE also noticed the following:

- In the redline version, the header still has "-1" throughout some of the change management documents of the Standard. Texas RE did notice the header was changed to PRC-025-2 in the clean version.
- Section "C: Compliance 1.3 Compliance Monitoring and Assessment Processes" appears to not follow the template for Results Based Standards. This version lists out the various compliance monitoring processes, whereas the template states: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Question 2	
• The Violation Severity Level table does not follow the template for Results Based Standards. • The introduction in Attachment 1, references "3.2 Facilities". Facilities are listed in section 4.2 of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The MW value (gross Real Power capability) reported to the Transmission Planner under MOD-025 is a minimum criteria for the determination of settings under PRC-025-2. Requiring the use of Facility ratings may not be indicative of the generator capability and could affect the sensitivity of the protection settings. The drafting team contends that a time horizon of "Long-term Planning" is correctly applied to Requirement R1 and is consistent with other similar requirements for setting protective relays. Other: • The software for creating the redline version did not correctly present the version change in the header. The drafting team will review redlines closer prior to posting. • The Compliance Enforcement Authority information has been updated to the template language. • The "VRF" column of the Violation Severity Level table has been removed to reflect the current template. • The reference to 3.2 Facilities in Attachment 1 has been corrected.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	
Document Name	
Comment	
1. We believe a performance-based criteria could be established for the Violation Severity Levels (VSLs) for this standard, similar to what is present for NERC Reliability Standard PRC-005-6. In that standard, the severity is based on a specific percentage of	

Question 2	
Components the applicable entity failed to maintain in accordance with minimum maintenance activities and maximum maintenance intervals. In this standard, a severe VSL is assessed when the entity fails to apply the required settings for any one load-responsive protective relay. We recommend a gradated approach based on the percentage of load-responsive protective relays where the entity failed to apply settings. This would complement the list of load-responsive protective relays identified as requested evidence in the standard's RSAW. 2. We ask the SDT to include hyperlinks for documents referenced as footnotes. The presence of multi-lined web addresses can inadvertently include extra spaces that corrupts or disables the link. 3. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. The concept of applying a graduated Violation Severity Level for Requirement R1 seems logical; however, the PRC-025 and PRC-005 performance is slightly different. In PRC-025, the performance is per relay and in PRC-005 it is based on a set of relays rather than individual. Therefore, the VSL must be based on a per relay violation and remain as written. 2. The drafting team will add the hyperlink to the documents as well as leaving the URL for reference. 3. Thank you for commenting.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	
Document Name	
Comment	
We appreciate the drafting team's consideration of our comments submitted on PRC-025-2, Draft 1. We believe the drafting team's response to our comment under Question 12 should be added as a footnote to Table 1. Specifically, consider adding the following as a clarifying footnote to Table 1: "The "gross MW capability reported to the Transmission Planner" is based upon NERC Reliability Standard MOD-025-2. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the	

Question 2	
Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The initial drafting team, as well as this drafting team, did not include the reference to the MOD-025-2 standard to avoid cases of version changes or where standards may become combined and the reference would become invalid. The language used in PRC-025 mimics the MOD-025 language. Additionally, there has been significant outreach to make the connection with the MOD-025 standard.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	
Support Comments submitted by the MRO NERC Standards Review Forum (NSRF)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to the MRO NSRF.	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	
Document Name	
Comment	

Question 2	
Comments were submitted as part of ACES Commnets.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response provided to ACES' comment(s).	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	
Document Name	
Comment	
Question for drafting team:	

Question 2	
"If a line connecting the GSU transformer(s) to the Transmission system has a load (that is not generating plant load) tapped to it, would Options 14, 15, or 16 apply at the remote end of the line? Would it apply at the high-side of the GSU transformer(s)? If the answer to both questions above is 'no,' then, if there are two lines connecting the GSU transformer(s) to the Transmission system, and one line has a load (that is not generating plant load) tapped to it, would Options 14, 15, or 16 apply at the high-side of the GSU transformer(s)?"	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team notes that the entity would need to determine the applicability of the line in question and apply the appropriate Reliability Standard. For example, use PRC-025 for lines that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant and for other lines use PRC-023 where appropriate. In the first case above, the applicable Element would be from the generating plant, including the high-side of the generating step-up transformer to the point tapped by the load. In the second case, the applicability of the Element remains unchanged by the tapped load. The drafting team acknowledges the above situation poses a unique circumstance with respect to the narrow applicability (i.e., no load serving); however, an entity should use good engineering judgement and apply the appropriate loadability settings (i.e., PRC-023 or PRC-025) to relays on Elements that are not specifically applicable to a Reliability Standard.	

Ruth Miller - Exelon - 5	
Answer	
Document Name	
Comment	
In the previous request for comments Exelon requested that the Project 2016-04 SDT evaluate the proposed fault detector settings associated with pilot wire communication systems. Specifically, Exelon stated in the response to Question 2 that "[c]alculations performed to calculate the settings for these type of relays show that the settings are very close to the 3-phase fault current contributed	

Question 2	
from the generator in cases where sub-transient reactance of the machine is at a high value. This will compromise the protection scheme because the changes proposed will make the protection scheme very insensitive. In case of a high resistance phase-to-ground fault, the protection scheme will not pick up the fault at the generator end. In some extreme cases, the fault detector relay (67 or 50), if set according to the current draft PRC-025 guidelines, may have to depend on the field forcing provided by the Automatic Voltage Regulator (AVR) before the fault current reaches the setpoint. This will induce unnecessary delays in the protective action and may cause more damage to the BES element." The SDT response to Exelon's comment was that this issue was "beyond the scope of the drafting team's work to revise PRC-025-1 as described in the SAR" and that an entity might have to "employ alternative protection schemes to achieve the loadability requirements and fault protection." Exelon does not agree that this is outside the scope of the SAR given consideration item (2) in the SAR specifically states that this project is to address the inclusion or exclusion of the 50 element. To address our concerns, Exelon requests the following changes: 1. The fault detector relays used in communication systems should be deleted from the scope of this standard because these particular relays are subject to misoperation only when the communication system has failed and there is a concurrent disturbance on the grid. 2. If there is any issue with a communication system and if the whole pilot protection scheme becomes a simple overcurrent relay, that condition is alarmed. Therefore, this condition would only exist for a short duration. To fix this condition the SDT can add a requirement to remedy this condition within a certain timeframe (e.g., correct condition within three months) and if not resolved then setpoints of 67 or 50 should be raised. 3. If the SDT still wants to retain these relays within the scope, then Exelon requests that the existing setting criteria should be modified as follows: i. “Minimum of the criteria 15a (or 15b) or 25% of the current contribution from the generator using a pre-fault voltage of 1.0 pu, generator sub-transient unsaturated reactance, and the main power transformer positive sequence reactance."	
Likes 0	
Dislikes 0	
Response	

Question 2	
Thank you for your comment. The drafting team understands the specifics of this unique case; however, the standard recognizes that an entity may need to replace or remove equipment that cannot achieve the intent of the standard while providing reliable fault protection.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	
Comment	
By adding the phrase “except that” to “Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.” in multiple places throughout the document, ambiguity is increased rather than decreased. LKE suggests replacing these instances with full, clearly worded sentences.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team notes that the phrase was added to make clear that it is acceptable for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant to also serve plants loads. This phrasing was corrected in version two because the original phrasing was not a complete sentence.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	
Document Name	PRC-025 modifications drawing.docx
Comment	

Question 2

Xcel Energy has concerns that the changes to the "Application" column for Options 7a-7c, 8a-8c, and 9a-9c are somewhat misleading and the description is inconsistent with Figure 5. We do acknowledge that this is partially a carryover issue from PRC-025-1.

The "Application" column for options 7, 8 & 9 describe "Relays installed on the generator side of the Generator step-up transformer..." Figure 5 shows that the current transformers for the load dependent relays to which options 7-9 are applicable are actually applied on the generator or the generator breaker and not specifically on the low side of the GSU. Note that many microprocessor based generator protection relays allow you to select the signal source for the current input to the 21 function such that either neutral or line side current transformers may be used for the current signal input to the 21 device associated with the generator. In other words, not all generator load dependent relays are fed neutral side current transformers. From this perspective, it would be unclear whether the entity should be using option 1a-1c or option 7a-7c for evaluating the loadability of the 21 function or options 2a-2c or option 8z-8c for the 50/51 functions.

Note that on Figure 5, the location of the generator breaker relative to the generator bus tap to the UAT is incorrect for most typical applicactions. In most applications when a generator breaker is provided, it will be on the generator bus between the generator and the bus tap to the UAT so that the UAT remains in service from the GSU when the generator breaker is open and the generator is offline. There would be operational value in a generator breaker between the UAT tap and GSU LV winding as shown in Figure 5. By moving the location of the generator breaker to the correct location between the generator and UAT bus tap on Figure 5, all inconsistency would be elimated and would greatly improve the clarity of the differences between options 1 vs. 7 and 2 vs. 8. See attached file for markup of Figure 5.

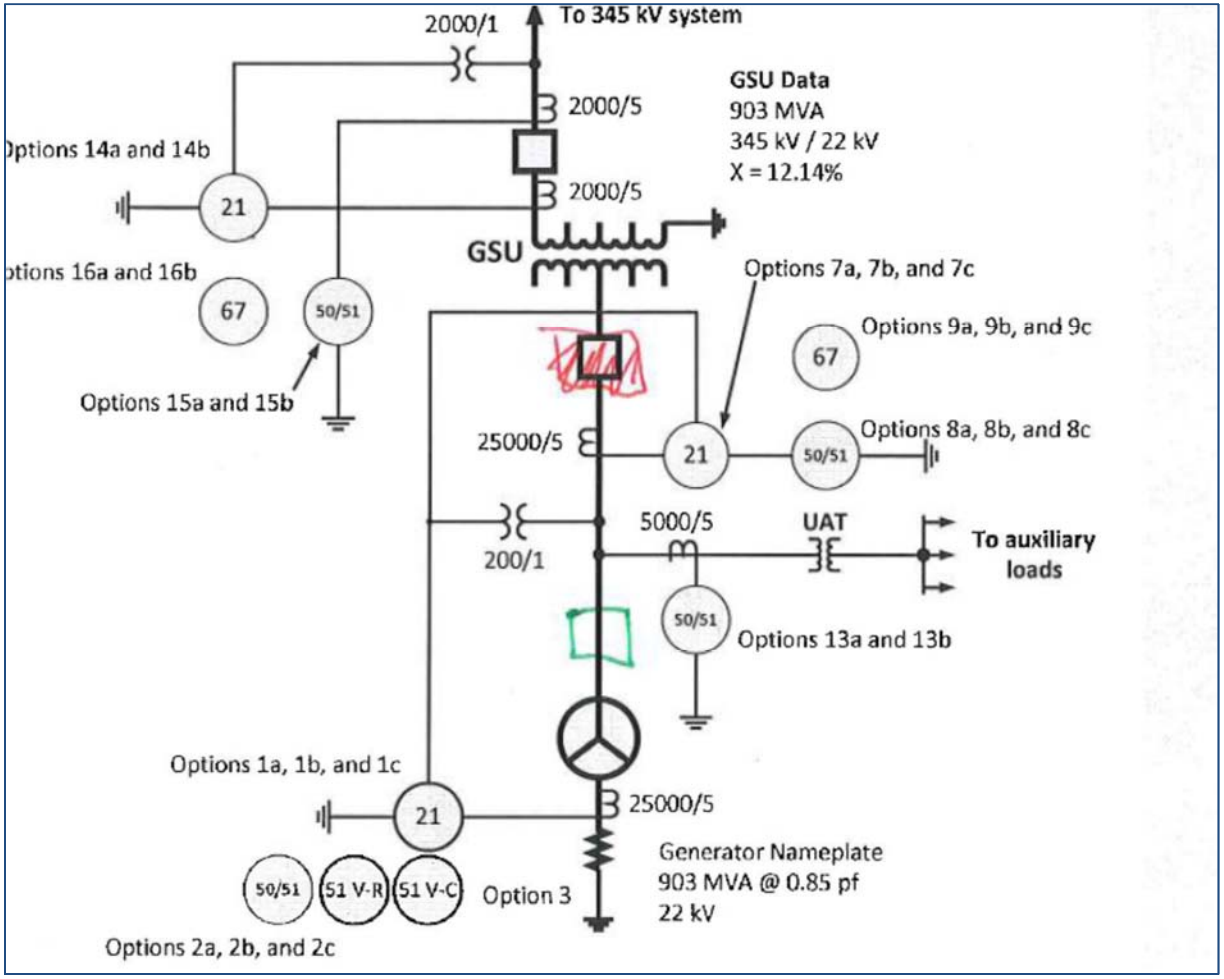
Based on the criteria included in the "settings criteria" colum for options 1, 2, 7 & 8, the key difference to use when determining which option to use is dependent on if the current transformer feeding the load dependent relay includes measurement of current flowing to the UAT in addition to that flowing to the LV winding of the GSU from the generator.

Beyond the above issue with the description clarity, we also have the following technical concerns with options 7 & 8 vs. options 1 & 2:

1. In many instances, in addition to the unit connected auxiliary transformer, a plant also likely has a 100% power capable system connected auxiliary transformer. In this case, the amount of power the plant would be capable of putting out would, to the system, be greater and the settings of any load dependent relay when the plant is fed from the system connected aus, should be based on that capability and calculated per option 1 or 2 and not for the lower value of aggregate power as allowed by option 7 or 8 - regardless of the location of the CT used to feed the load dependent relay. If an entity's reported max gross MW value is based

Question 2
on the gross output when fed from the system connected auxiliary source, then the entity should have to use option 1 or 2 regardless of the configuration of the current transformer relative to the unit connected auxiliary transformer. Option 7 or 8 should only be allowed if the max gross MW reported is based on the reduced output available when the unit is receiving auxiliary power from the unit connected auxiliary transformer. 2. The differences in determining real power between options 1 and 2 vs. 7 adn 8 is understandable, but it is unclear why the reactive power used in option 7 & 8 are calculated differently than that used in options 1 & 2. What is the technical justification for the difference? The response of the machine to depressed grid voltages and field forcing capability will be the same regardless of where the load dependent relay current transformer is located relative to the aux power tap. Using a reduced value for field forcing MVAR based on aggregate MW output rather than a MW value based strictly on nameplate MVA and rated pf does not seem justified.

Question 2



Likes 0	
Dislikes 0	

Response

Question 2	
Thank you for your comment. Options 1a-1c and 7a-7c are differentiated by where the current transformer (CT) is located and not the breaker location. Options 2a-2c and 8a-8c are also differentiated by where the current transformer (CT) is located and not the breaker location. Options 7a-7c and 8a-8c are generally transmission related to address varying entity configurations. For example, where a Transmission Owner owns the generator step-up (GSU) transformer. Option 1a-1c and 2a-2c are directed to Generator Owner protection relaying. The representation of the breaker in Figure 5 is for illustration and may not be representative of all configurations. Technical response: 1. PRC-025 calculations are based upon the gross Megawatt Capability (MW) value reported to the Transmission Planner under MOD-025 and not the net MW. PRC-025 also does not take into account any deductions in MW for a unit auxiliary transformer (UAT) that is connected on the generator bus or to the system. Option 1a-1c does not use the term "aggregate" because it is addressing a single generating unit. Options 7a-7c and 8a-8c may include multiple generators connected to a single GSU transformer; therefore, the "aggregate" gross MW capability must be used in the determination of settings. 2. There is no difference in determining the Real Power or Reactive Power for Options 1a-1c/2a-2c and Options 7a-7c/8a-8c. The only difference is that Options 7a-7c and 8a-8c account for where there are multiple (i.e., "aggregate") generators connected to a single GSU transformer.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
The Exclusions section should also exclude the following protection system based on footnote 1 in the Applicability Section: Low voltage protection devices that do not have adjustable settings.	
Likes 0	
Dislikes 0	
Response	

Question 2	
Thank you for your comment. The drafting team has added the exclusion in Attachment 1.	
Tom Haire - Rutherford EMC - 3	
Answer	
Document Name	
Comment	
Section 4.2.5 should have a minimum threshhold.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Facilities in Section 4.2.5 does not include a threshold because the applicability is driven by whether the resource(s) in Section 4.2 meets the I-4 Inclusion of the Bulk Electric System definition as stated in the Glossary of Terms Used in NERC Reliability Standards.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017
Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period	October 30, 2017 through December 14, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

    4.1.2. Transmission Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

    4.1.3. Distribution Provider that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

    4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

    4.2.1. Generating unit(s).

    4.2.2. Generator step-up (i.e., GSU) transformer(s).

    4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

    4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.

    4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf).

and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. **Evidence Retention:** The following evidence retention period(s) 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 Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, “Considerations for Power Plant and Transmission System Protection Coordination,” technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition.” (Date of Publication: March 2016)

IEEE C37.102-2006, “IEEE Guide for AC Generator Protection.” (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04
2	TBD	Adopted by NERC Board of Trustees	Revision
2	TBD	FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[7] If the relay is installed on the high-side of the GSU transformer use, Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[8] If the relay is installed on the high-side of the GSU transformer use, Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51)[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

A different application starts on the next page

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.
[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[13] If the relay is installed on the generator-side of the GSU transformer, use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) –connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

[14] If the relay is installed on the generator-side of the GSU transformer, use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer, use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[17] If the relay is installed on the generator-side of the GSU transformer, use Option 12.

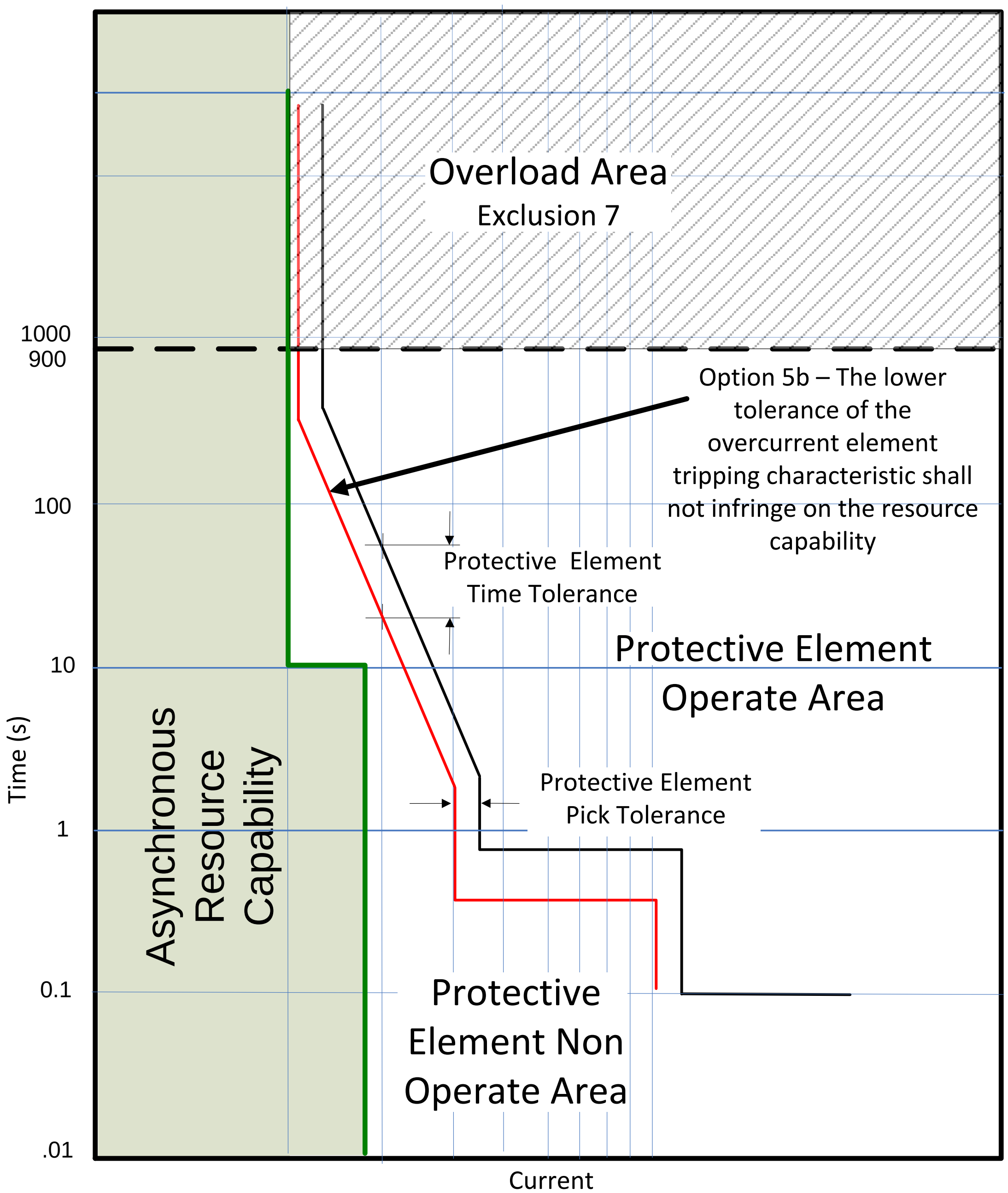


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

---

[18] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

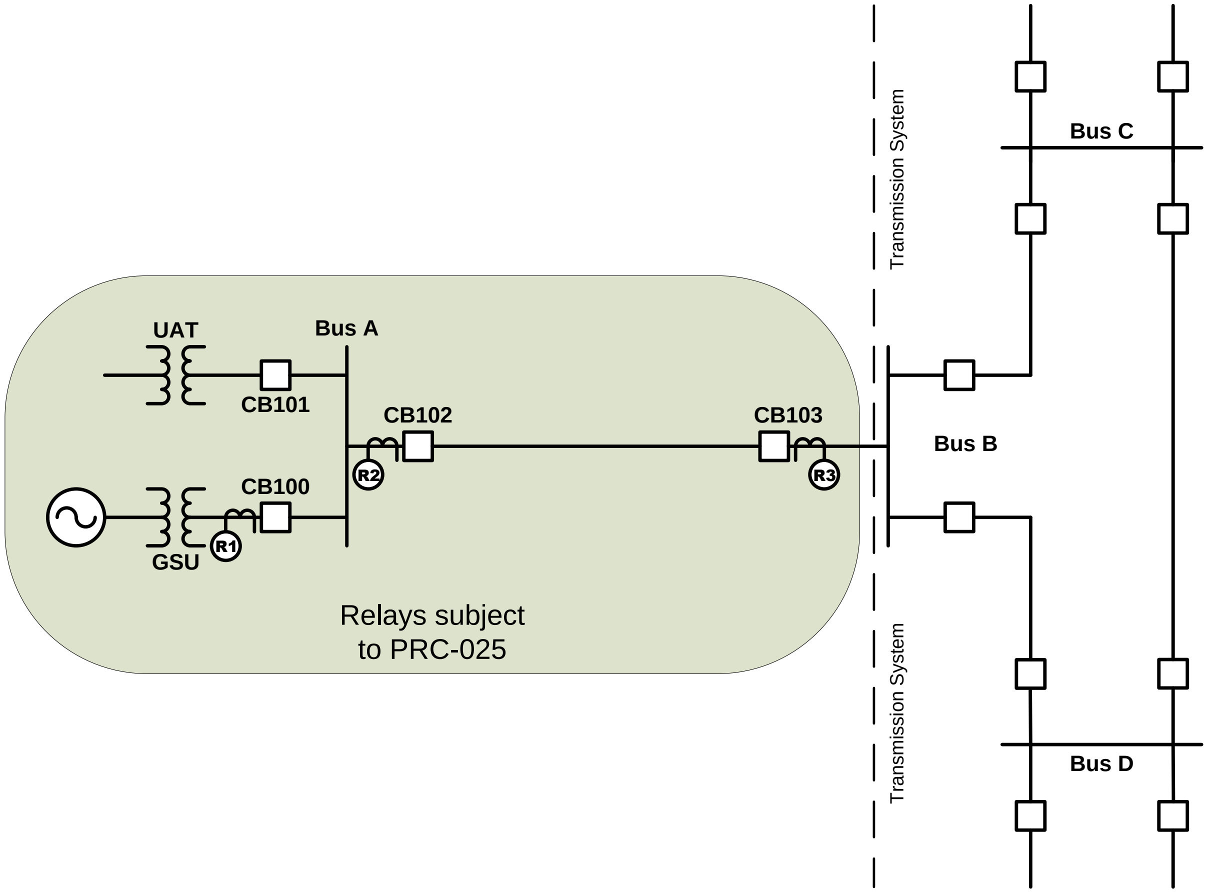


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

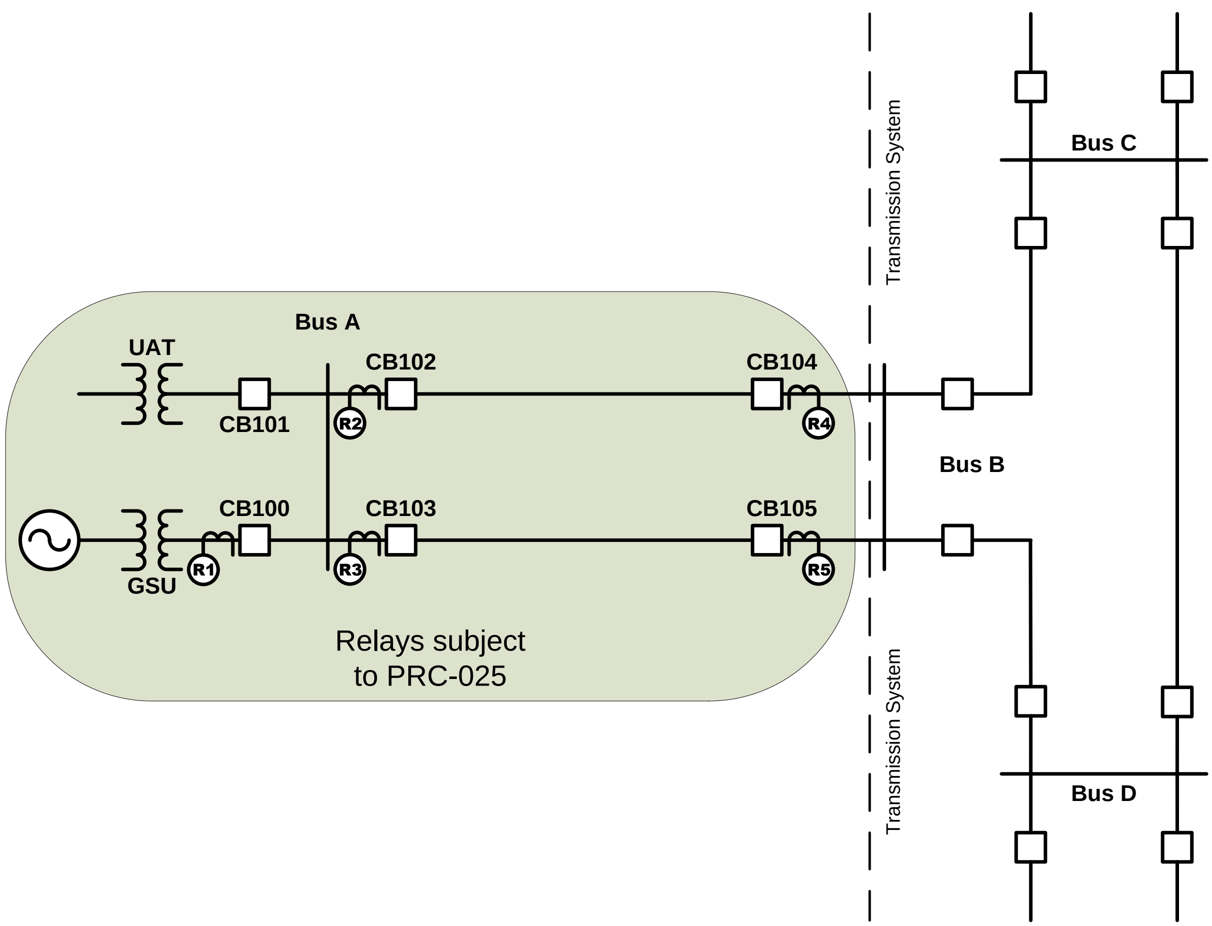


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

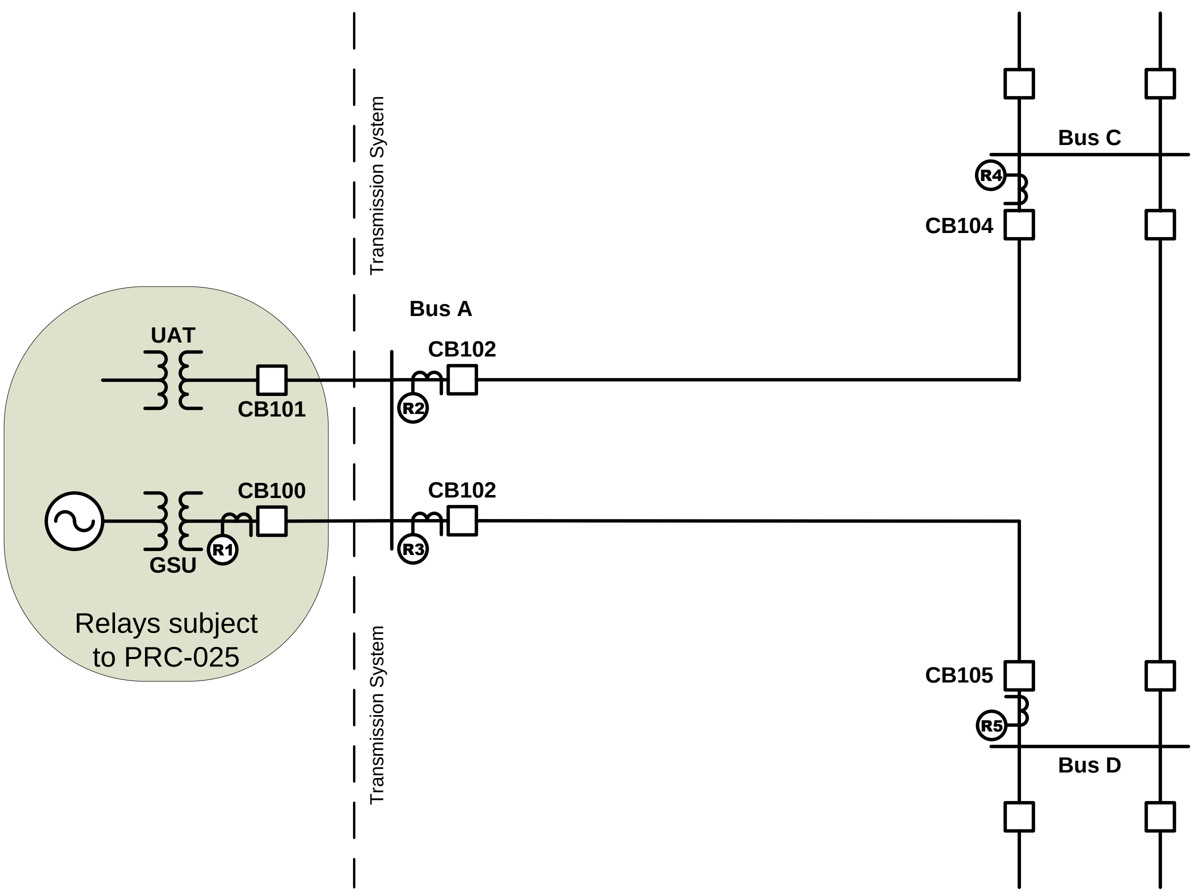


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

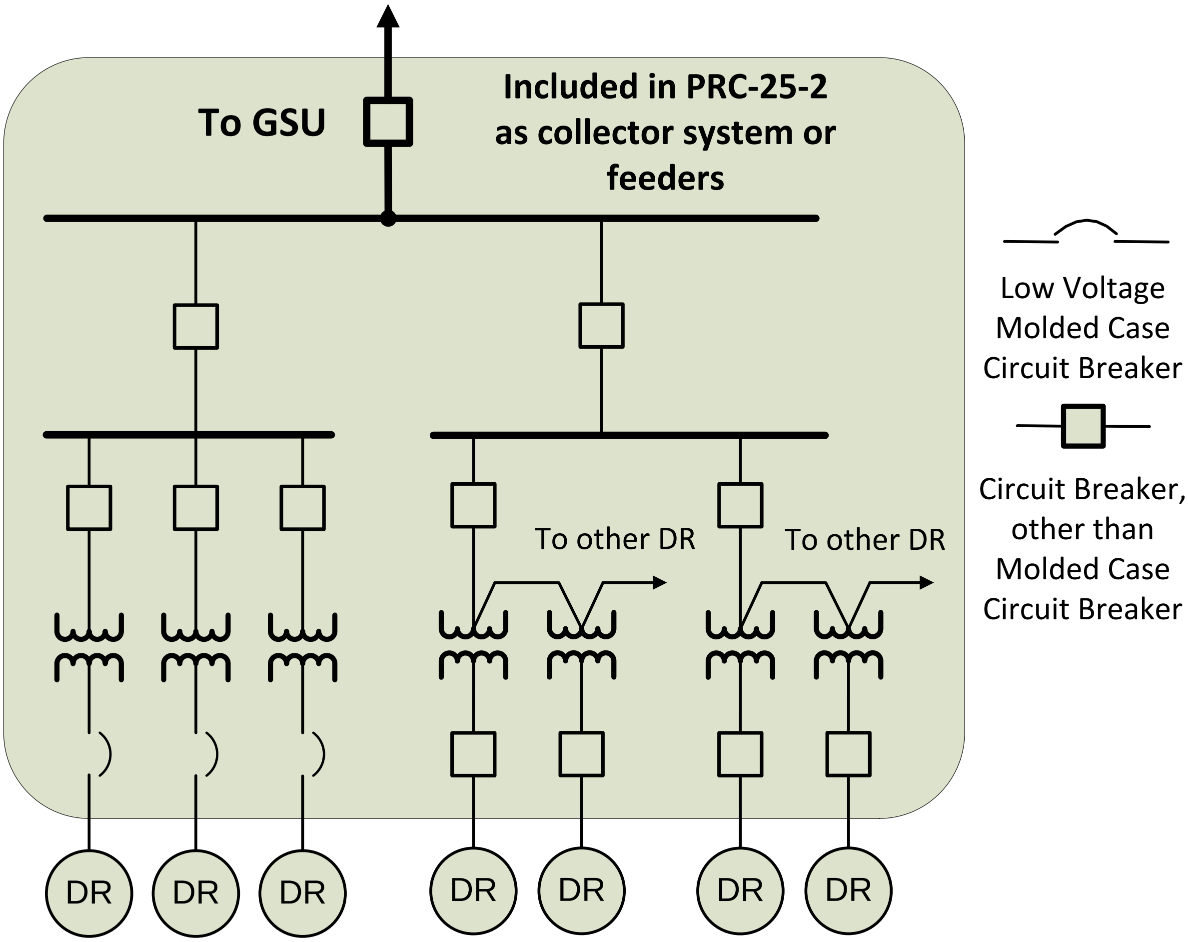


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

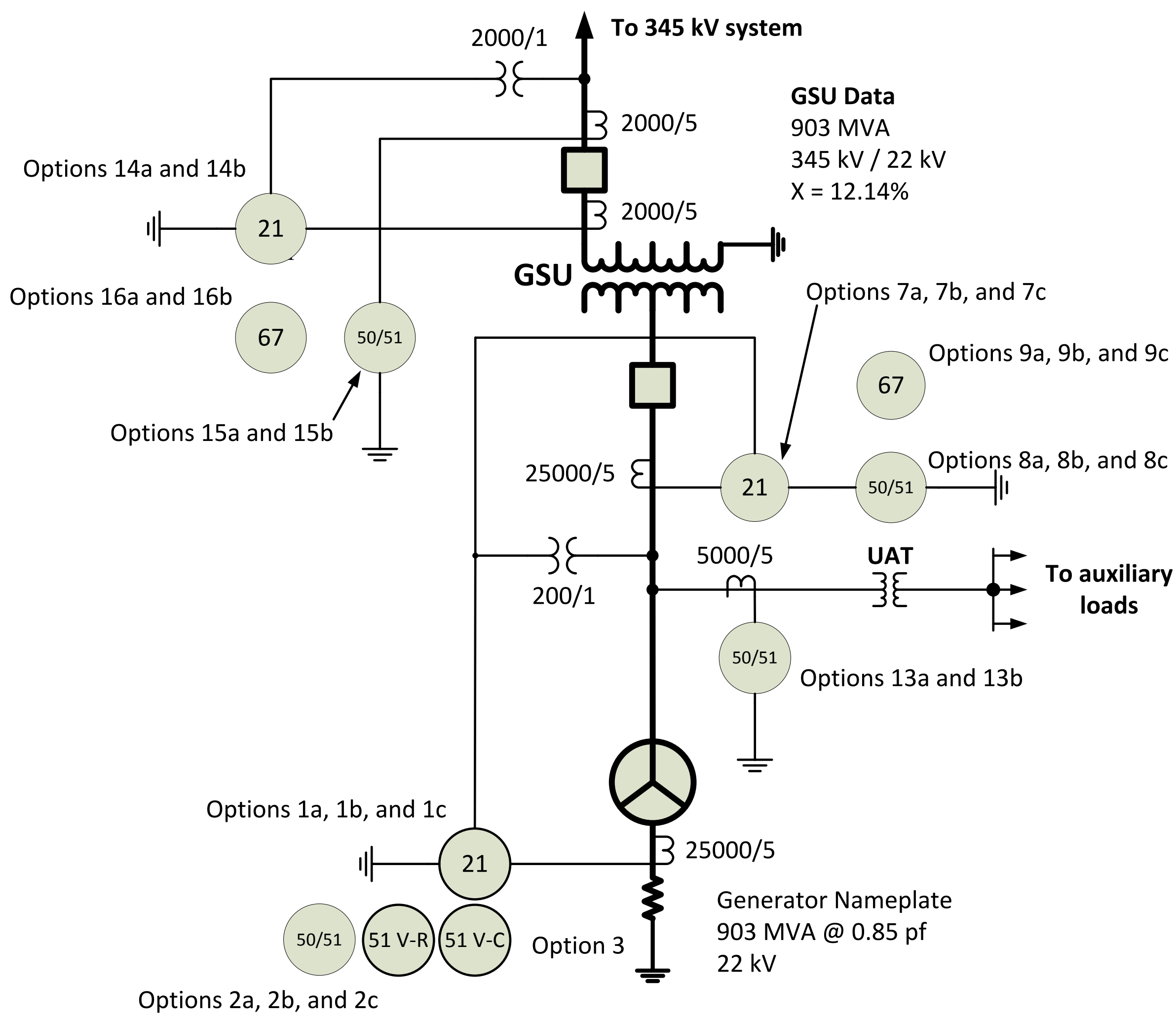


Figure 5: Relay Connection for corresponding synchronous options

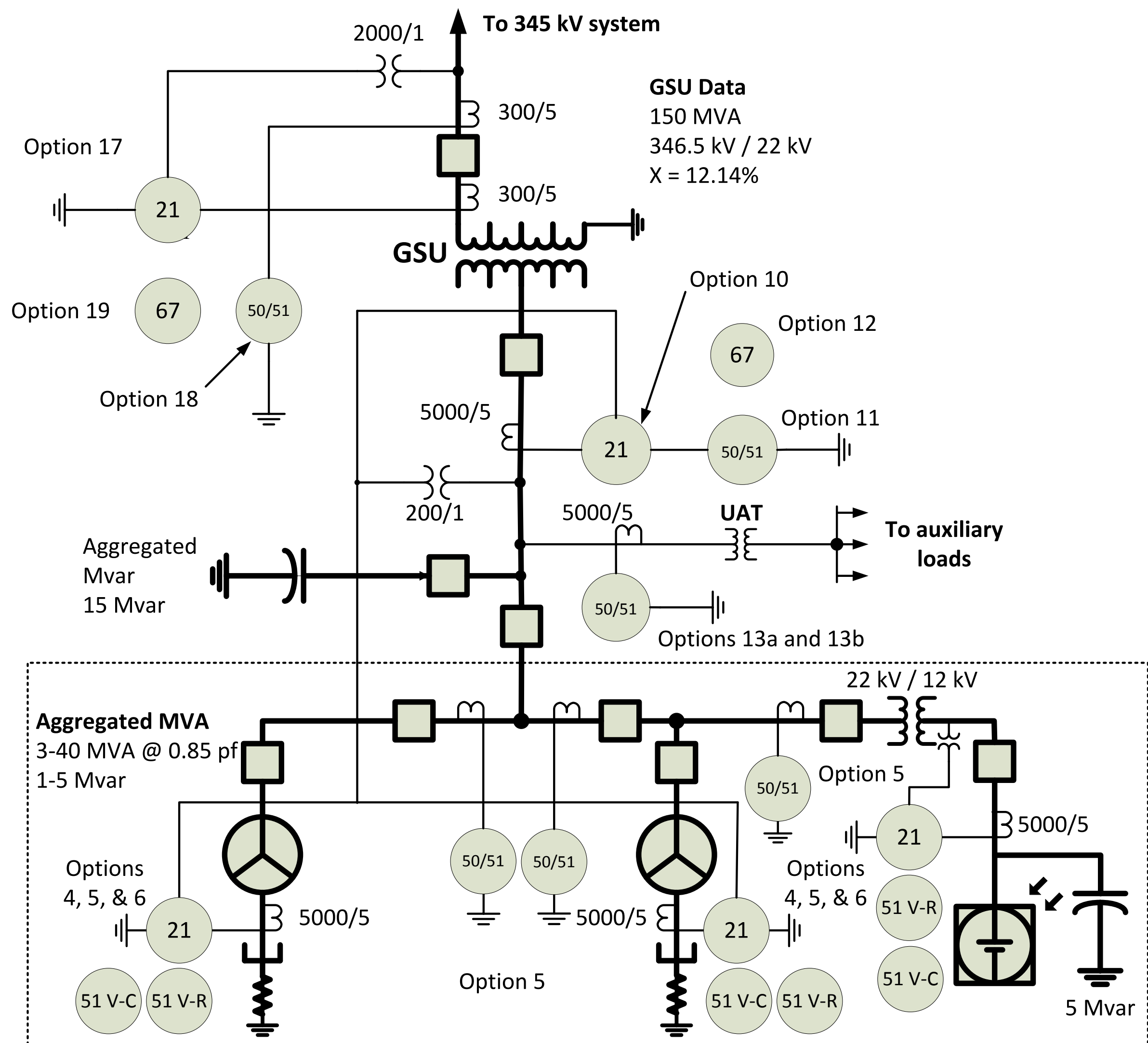


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer’s turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

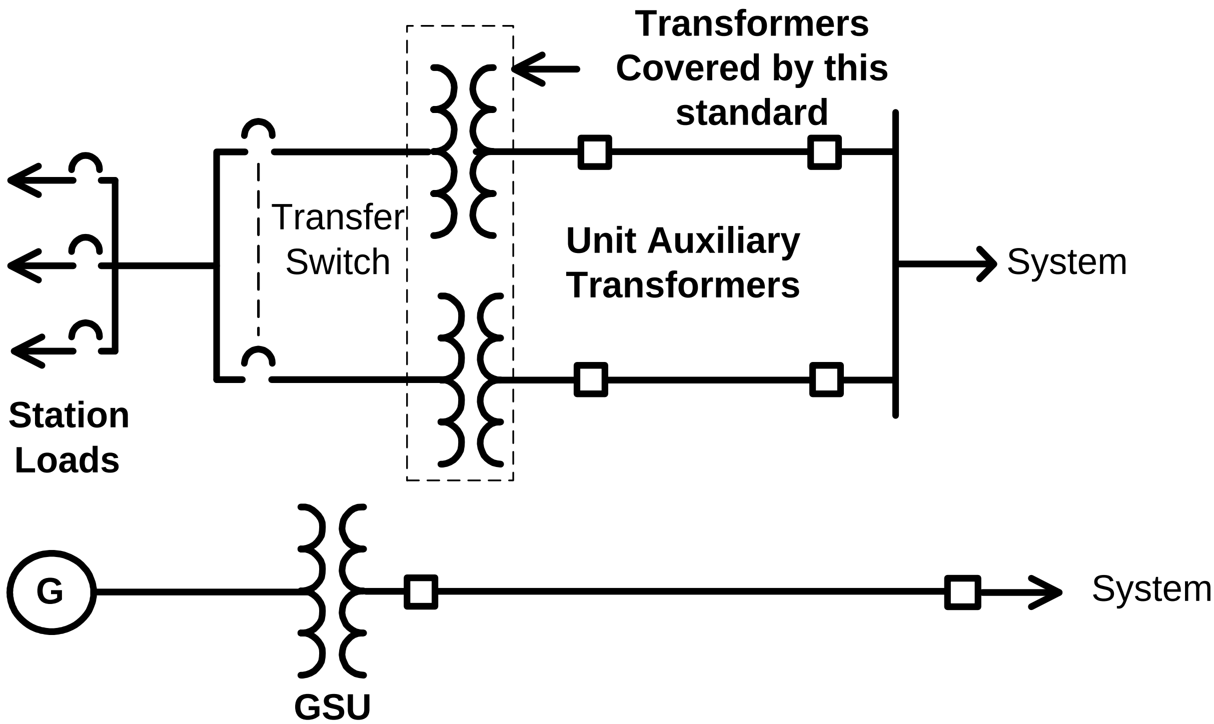


Figure 7: Auxiliary Power System (independent from generator)

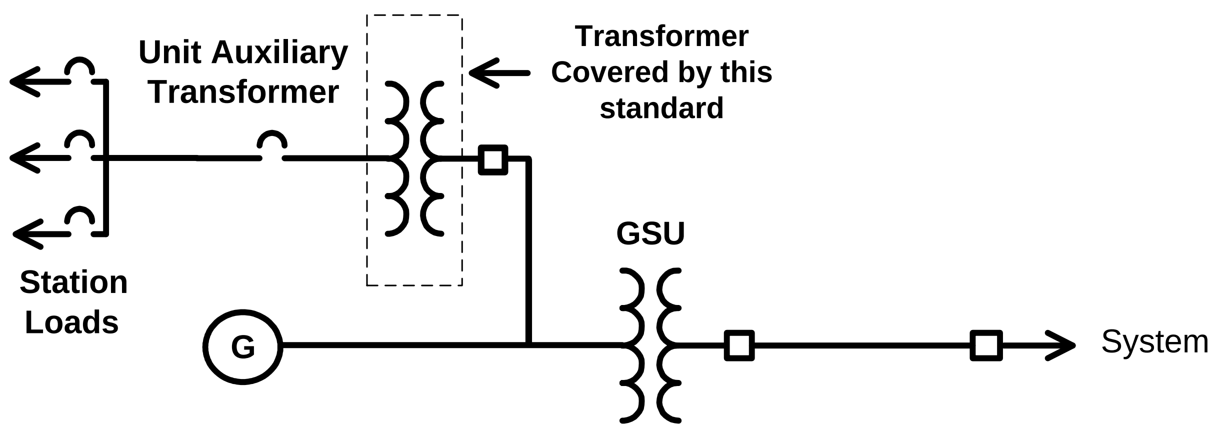


Figure 8: Typical auxiliary power system for generation units or plants

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at

the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$ $pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (*MVA_{base}*):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\mathrm{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\mathrm{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\mathrm{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\mathrm{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

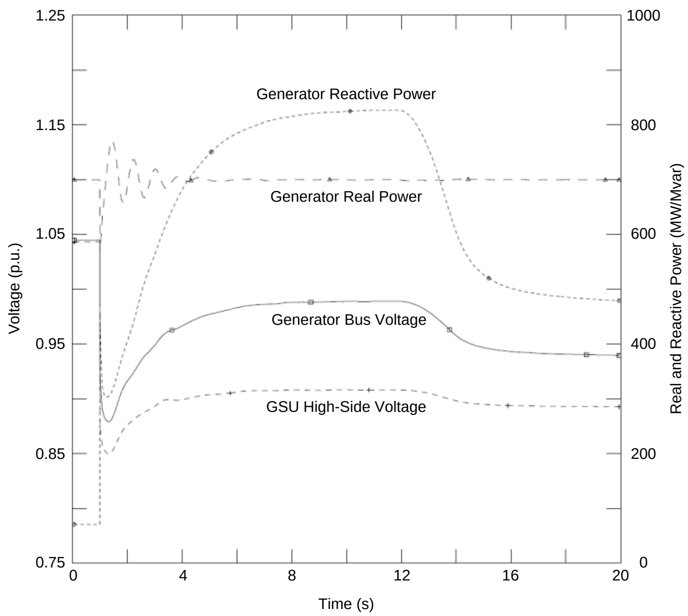
$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $P_{pu} = \dfrac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $Q_{pu} = \dfrac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Option 2b

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left|V_{high-side}\right|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8441 \pm 1.1541}{2}$$

$$\left|V_{low-side}\right| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

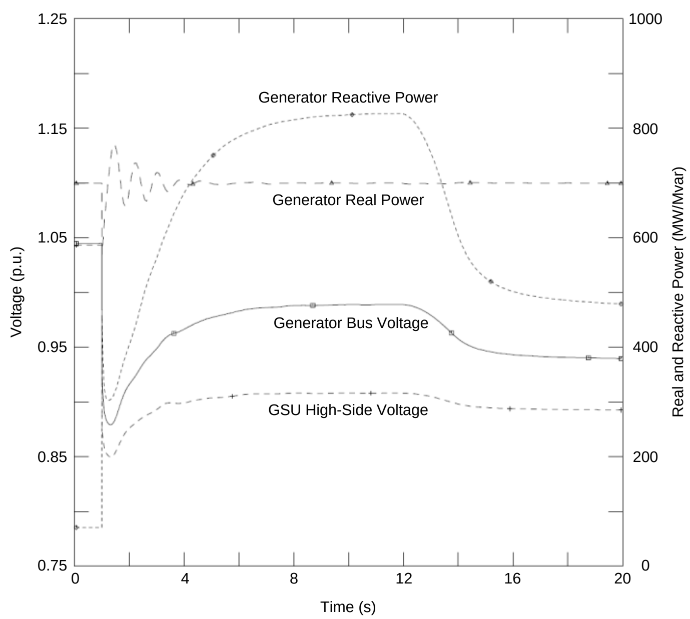
$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = \ GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° \ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \ MVA \ \times 0.85$$

$$P = 102.0 \ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \ Mvar + 5 \ Mvar + (3 \times 40 \ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0 \ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \ kV \times \left(\frac{22 \ kV}{346.5 \ kV}\right)$$

$$V_{gen} = 21.9 \ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0 \ MW + j83.2 \ Mvar$$

$$S = 131.6\angle 39.2° \ MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < \ 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = \ GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S_{Synch}^{*}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7° \, A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \, MVA \times 0.85$$

$$P_{Asynch} = 102.0 \, MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \, Mvar + 5 \, Mvar + (3 \times 40 \, MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \, Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \, kV \times \left(\frac{22 \, kV}{346.5 \, kV}\right)$$

$$V_{gen} = 20.81 \, kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \, MW + j83.2 \, Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2° \, MVA$$

Primary current ($I_{pri-async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2° \; MVA}{1.73 \times 20.81 \; kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \; A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \; A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \; A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \; A \times 1.00$$

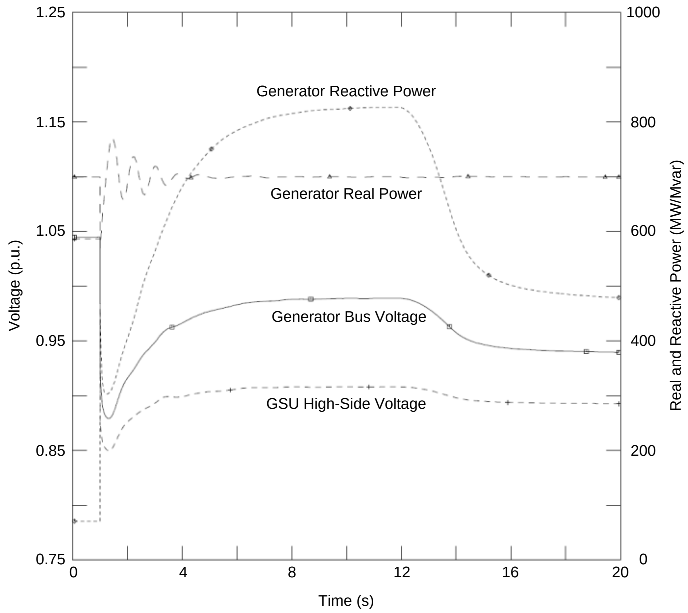
$$I_{\sec limit} > 9.514 \angle -56.8° \; A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle -39.2° \ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \ MVA}{1.73 \times 13.8 \ kV}$$

$$I_{pri} = 2510.2 \ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51 \ A \times 1.50$$

$$I_{\sec limit} > 3.77 \ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = \ GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u.\times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\mathrm{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\mathrm{sec}\,limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\mathrm{sec}\,limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\mathrm{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

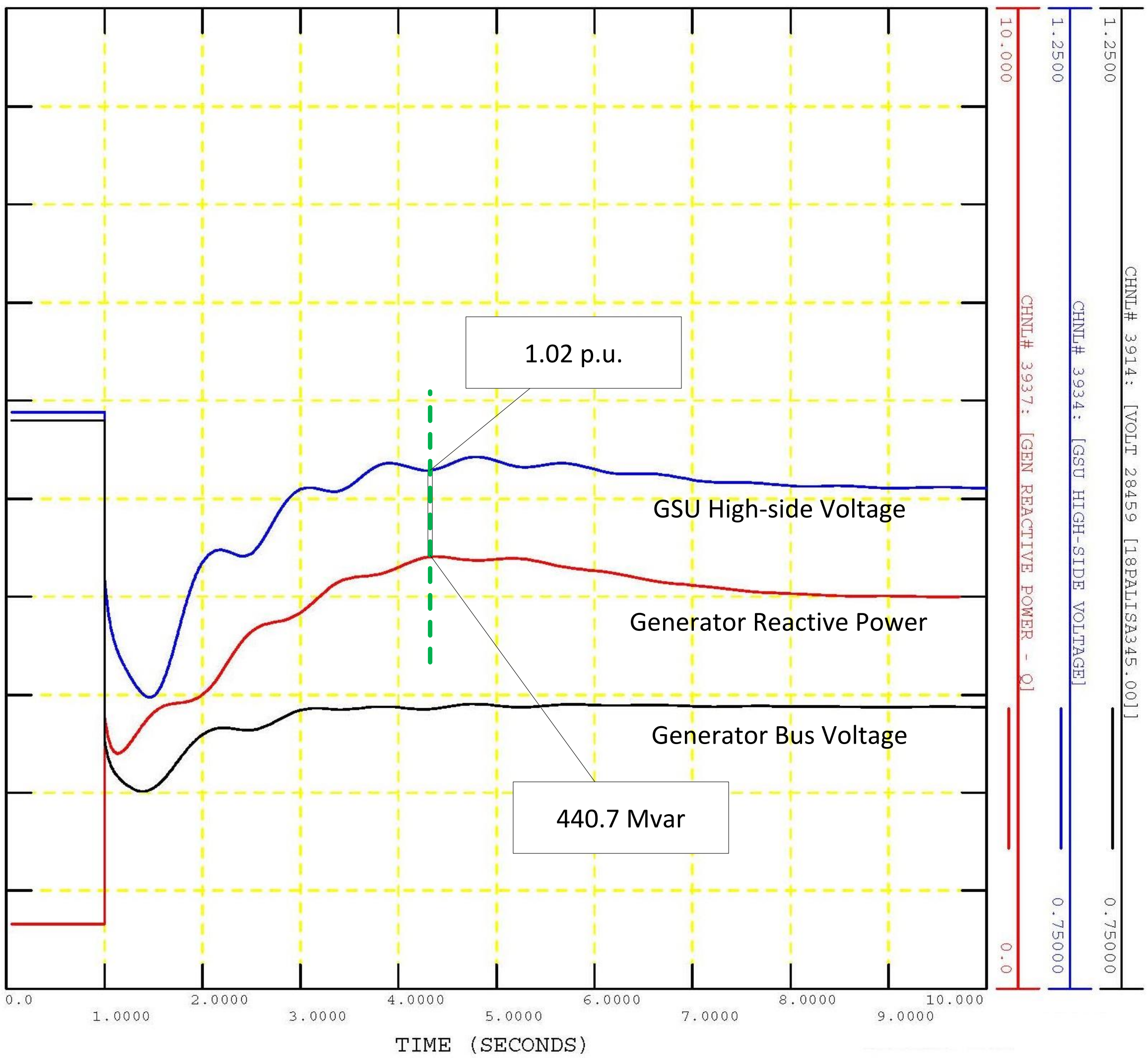
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (152) $S = P_{Synch\_reported} + jQ$

Example Calculations: Option 14b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle - 52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle - 52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle - 52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\angle - 52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

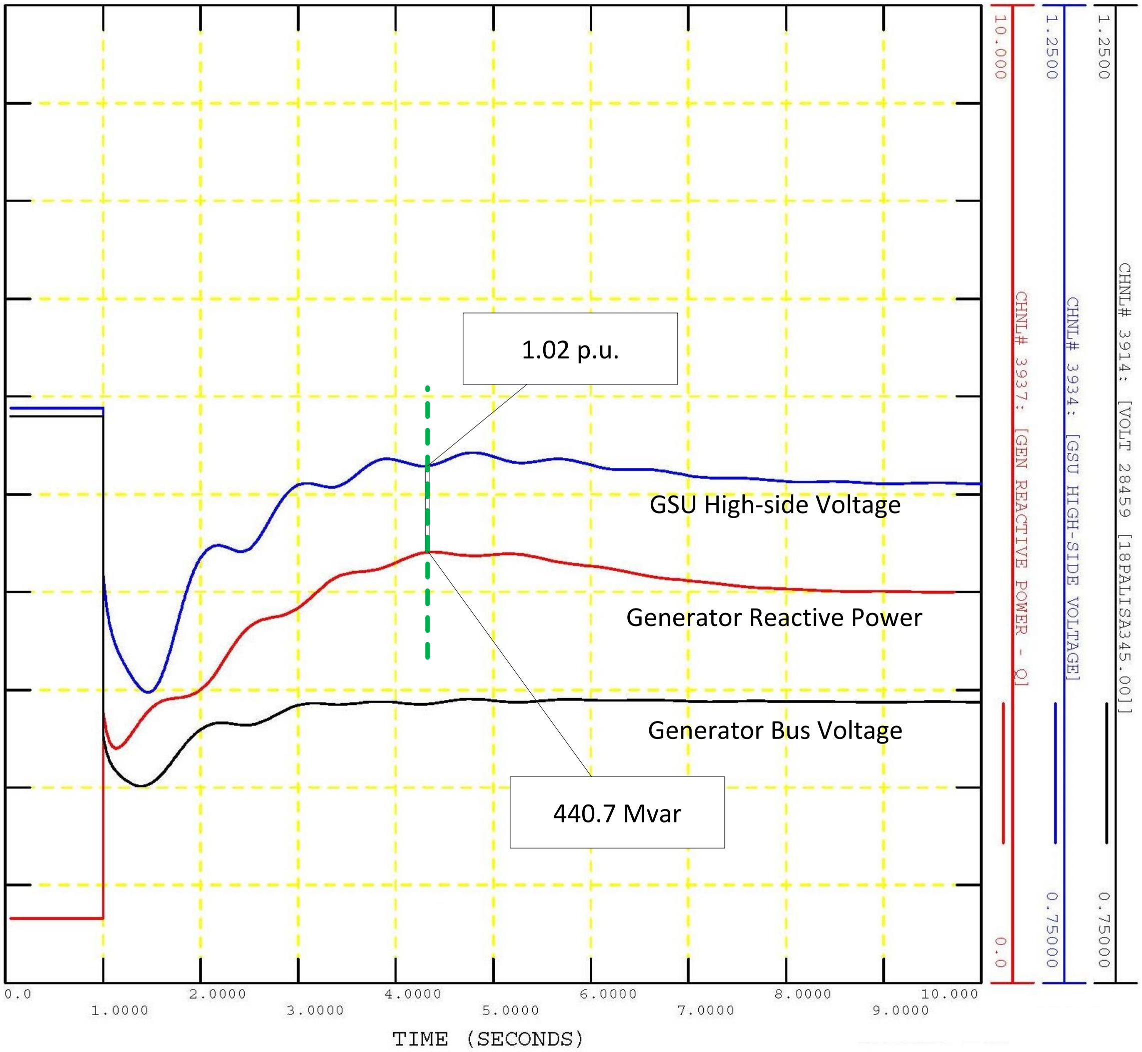
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

Example Calculations: Options 15b and 16b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 3.39\angle -32.2°\ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 3.39\angle -32.2°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 3.90\angle -32.2°\ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

Eq. (175) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

Eq. (176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

Example Calculations: Options 18 and 19

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\mathrm{sec}\,limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017
Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period	October 30, 2017 through December 14, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.
     - **4.1.2.** Transmission Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.
     - **4.1.3.** Distribution Provider that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.
   - **4.2. Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:
     - **4.2.1.** Generating unit(s).
     - **4.2.2.** Generator step-up (i.e., GSU) transformer(s).
     - **4.2.3.** Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]
     - **4.2.4.** Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.
     - **4.2.5.** Elements utilized in the aggregation of dispersed power producing resources.
5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

1. **Compliance Monitoring Process**

   ~~1.1.~~ **Compliance Enforcement Authority**

   ~~1.2.~~1.1. ~~As defined in the NERC Rules of Procedure,~~: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles

[3] Interim Report ~~Interim Report:~~: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf).

of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

~~1.3.~~1.2. **Evidence Retention:** The following evidence retention ~~periods~~period(s) 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 Compliance Enforcement Authority ~~(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 ~~Generator Owner, Transmission Owner, and Distribution Provider~~applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~CEA~~Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.~~

~~**1.4. Compliance Monitoring and Assessment Processes**~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~**1.5. Additional Compliance Information**~~

- ~~None.~~

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-Term Planning~~	~~High~~	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

Deleted Cells

Deleted Cells

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, "Considerations for Power Plant and Transmission System Protection Coordination," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04~~Revision~~
2	TBD	Adopted by NERC Board of Trustees	Revision
2	TBD	FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in ~~3~~4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[7] If the relay is installed on the high-side of the GSU transformer use, Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[8] If the relay is installed on the high-side of the GSU transformer use, Option 16.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51)[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

A different application starts on the next page

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.
[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[13] If the relay is installed on the generator-side of the GSU transformer, use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) –connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[14] If the relay is installed on the generator-side of the GSU transformer, use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer, use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[17] If the relay is installed on the generator-side of the GSU transformer, use Option 12.

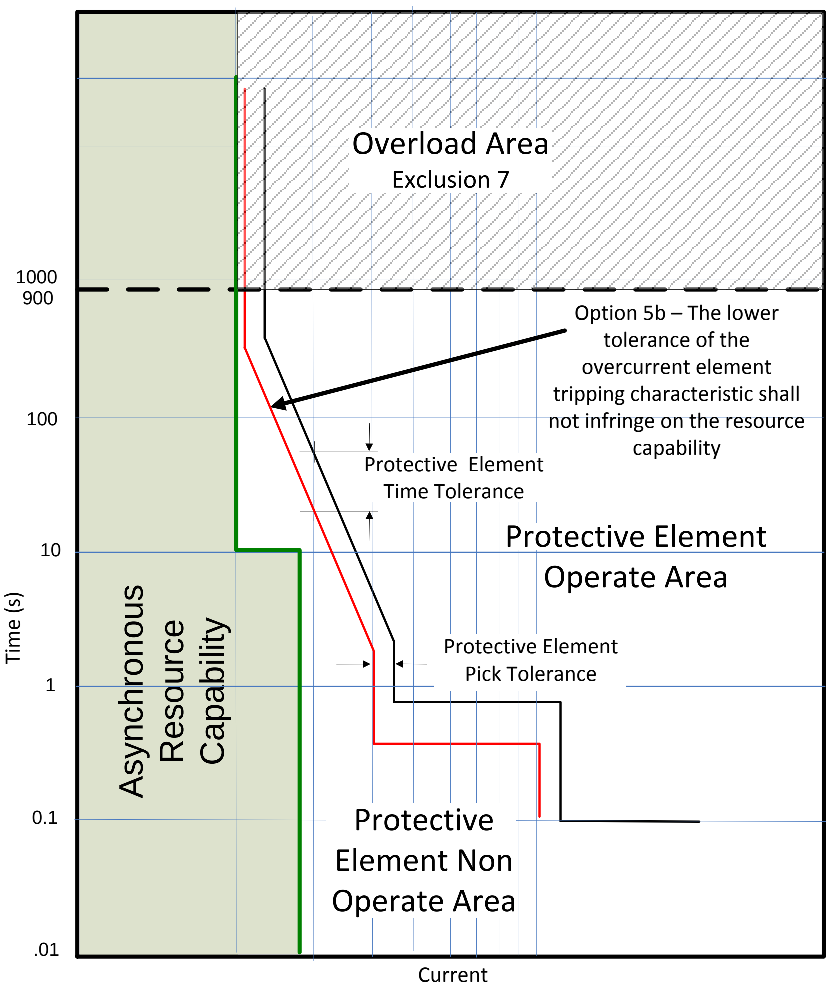


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination~~"Considerations for Power Plant and Transmission System Protection Coordination,"~~," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard

[18] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance ~~is~~are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of

Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

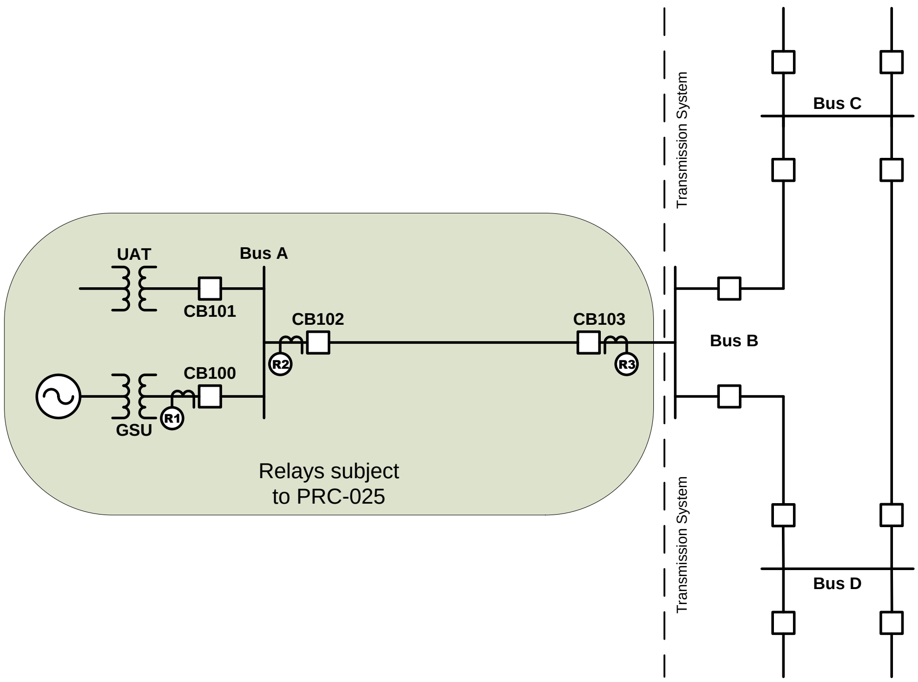


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

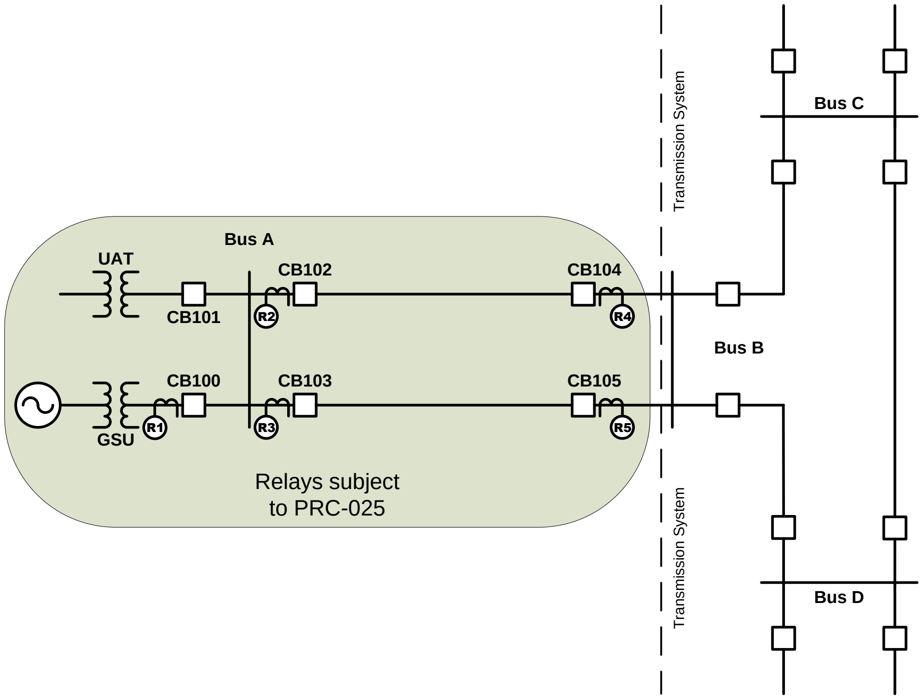


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

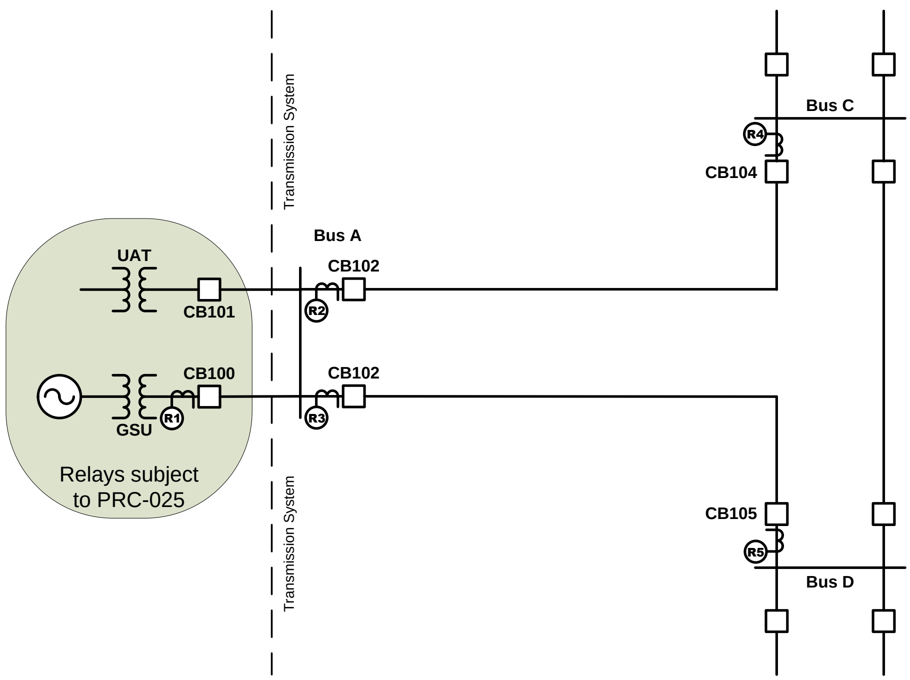


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*~~*Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,~~,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system” or “feeders”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

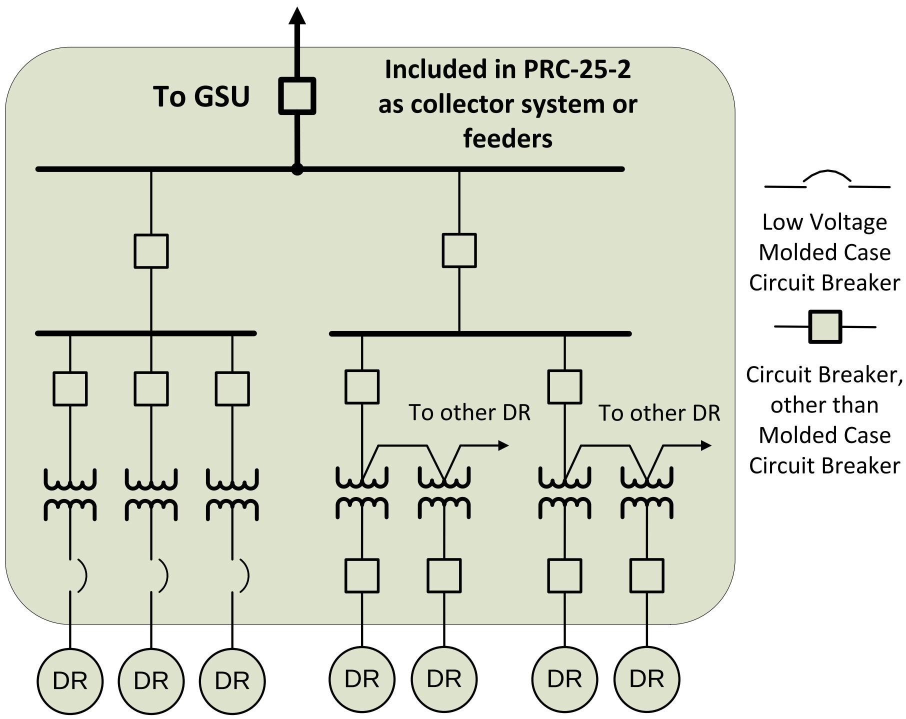


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)
The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)
See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)
Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)
Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)
See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

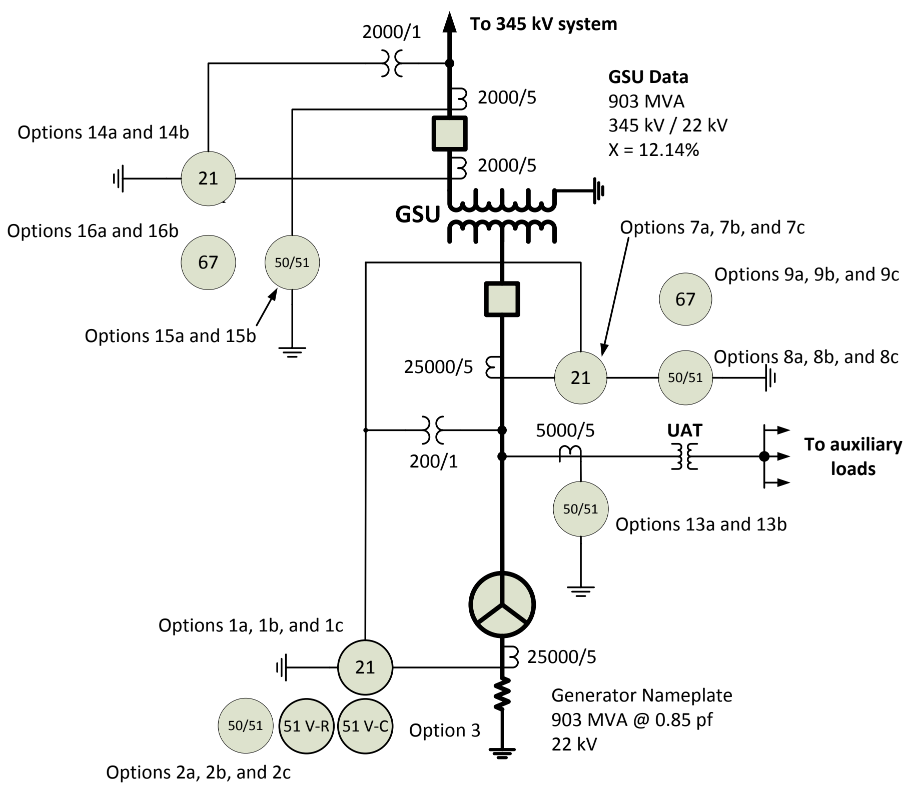


Figure 5: Relay Connection for corresponding synchronous options

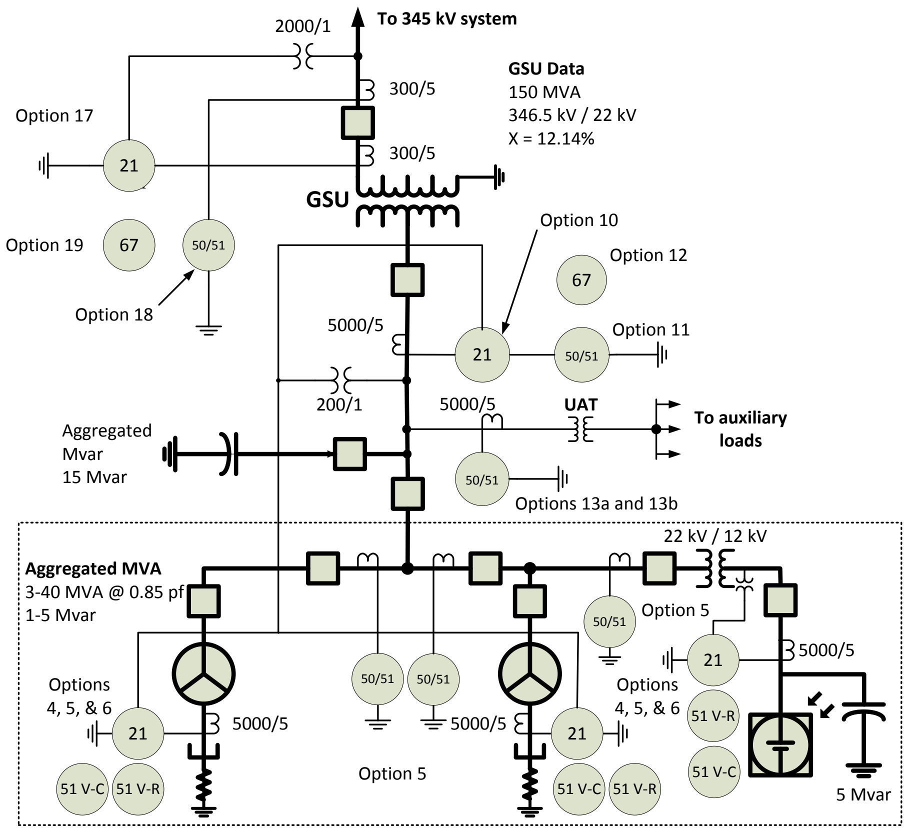


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

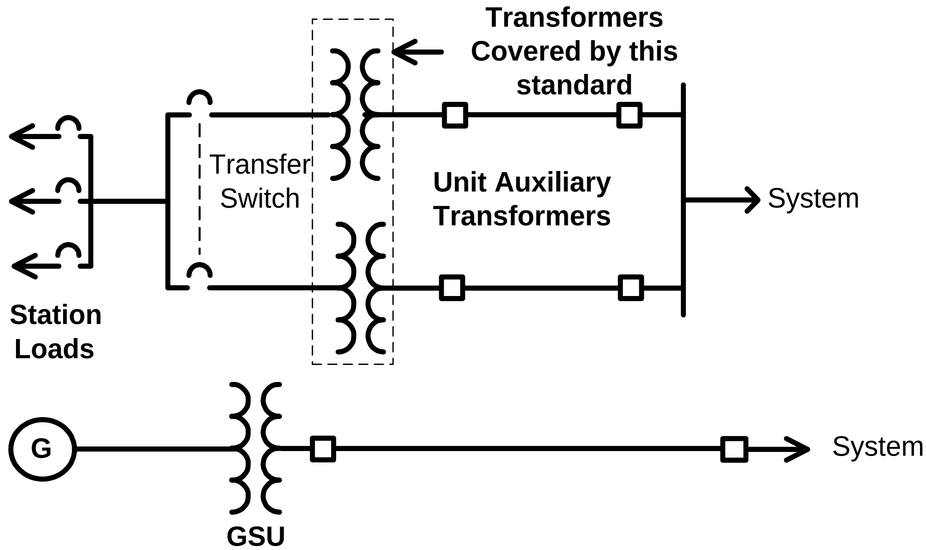


Figure 7: Auxiliary Power System (independent from generator)

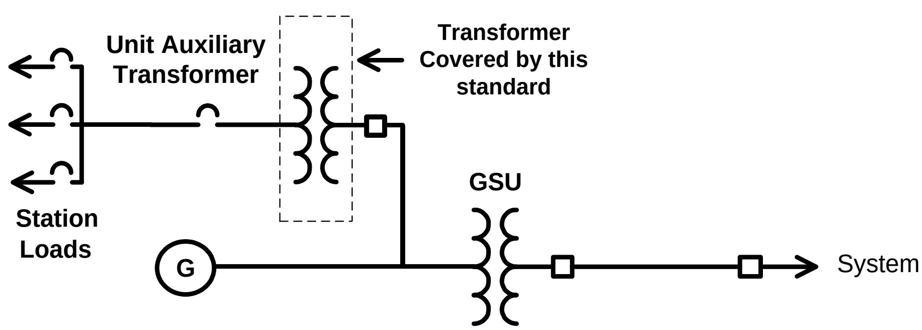


Figure 8: Typical auxiliary power system for generation units or plants

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at

the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle-58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

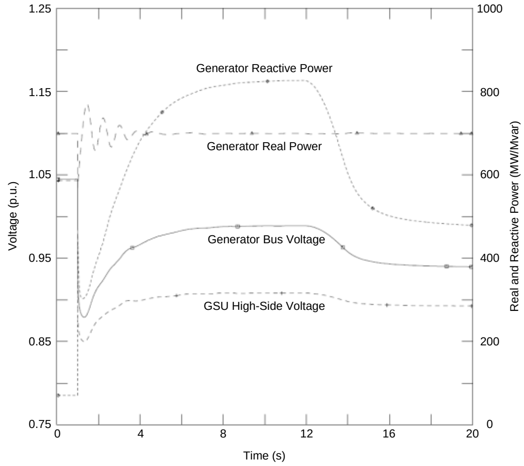
$$Z_{max} < \frac{7.74\,\Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\,\Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Option 2b

Transformer impedance:

Eq. (40) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times \left|X_{pu}\right|\right)}{\left(\left|V_{low-side}\right| \times \left[V_{high-side}\right]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$\left|V_{low-side}\right| = \frac{\left|V_{high-side}\right| \times \cos(\theta_{low-side}) \pm \sqrt{\left|V_{high-side}\right|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$\left|V_{low-side}\right| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$\left|V_{low-side}\right| = \frac{0.8449 \pm 1.1546}{2}$$

$$\left|V_{low-side}\right| = 0.9998\, p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = \left|V_{low-side}\right| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

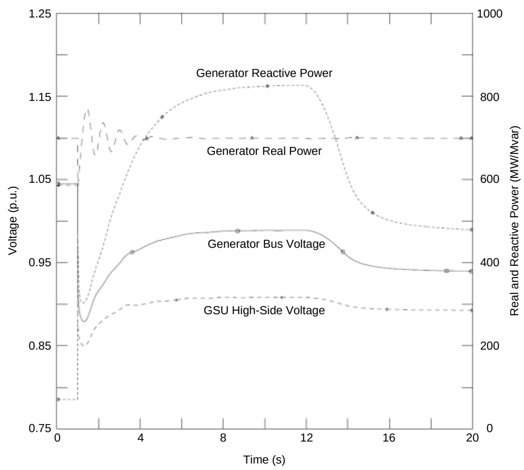
$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P =\ GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{sec\,limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $S = P + jQ$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $I_{sec} = \dfrac{I_{pri}}{CT_{Asynch\_ratio}}$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $I_{\sec limit} > I_{sec} \times 130\%$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2° \, MVA}{1.73 \times 21.9 \, kV}$$

$$I_{pri} = 3473\angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2° \, A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2° \, A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903 \, MVA \times 0.85$$

$$P_{Synch} = 767.6 \, MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$Q_{Synch} = 1.50 \times 767.6\ MW$

$Q_{Synch} = 1151.3\ MW$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + \ 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30\ \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $Z_{\sec limit} = \dfrac{Z_{sec}}{100\%}$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \,\Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \,\Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $Z_{max} < \dfrac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent~~s~~ the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent~~s~~ a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU ~~T~~transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\, p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri-sync}$):

Eq. (114) $I_{pri-sync} = \dfrac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7° \ A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \ MVA \times 0.85$$

$$P_{Asynch} = 102.0 \ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \ Mvar + 5 \ Mvar + (3 \times 40 \ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \ kV \times \left(\frac{22 \ kV}{346.5 \ kV}\right)$$

$$V_{gen} = 20.81 \ kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \ MW + j83.2 \ Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2° \ MVA$$

Primary current ($I_{pri-async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2° \, MVA}{1.73 \times 20.81 \, kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A \times 1.00$$

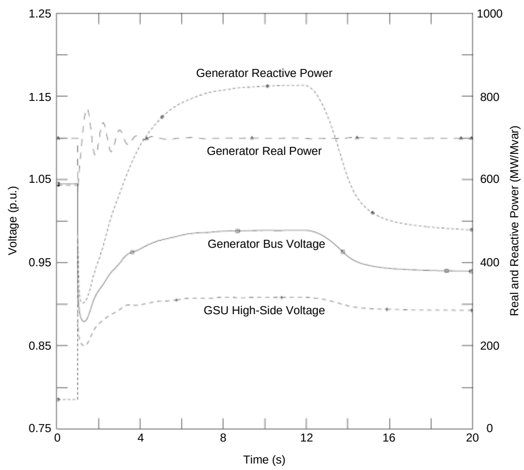
$$I_{\sec limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \mathrm{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

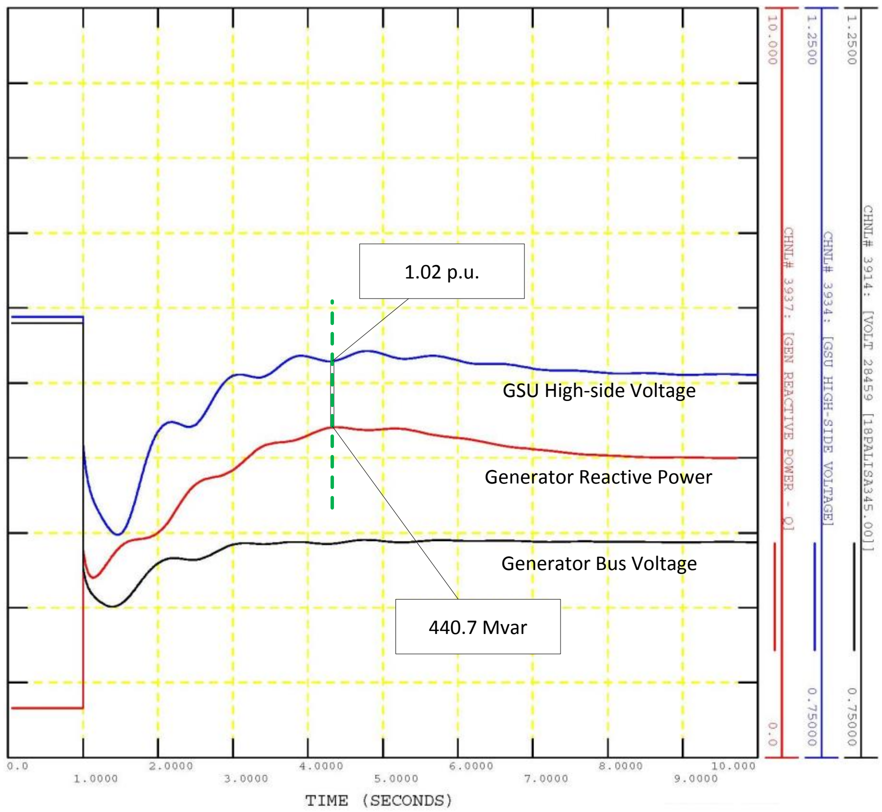
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (152) $S = P_{Synch\_reported} + jQ$

Example Calculations: Option 14b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at ~~at~~ the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle -52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

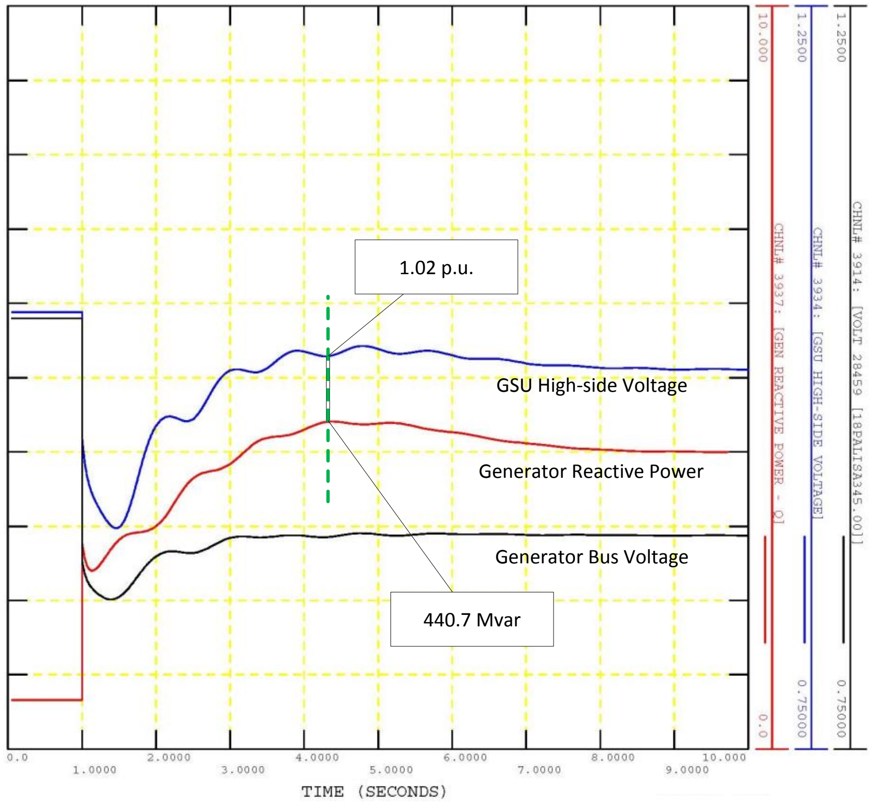
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

Example Calculations: Options 15b and 16b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 3.39\angle -32.2°\ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 3.39\angle -32.2°\ A \times 1.15$$

$$I_{\sec limit} > 3.90\angle -32.2°\ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

Eq. (175) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q):

Eq. (176) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$V_{gen} = 1.0 \times 345\ kV$

$V_{gen} = 345.0\ kV$

Apparent power (S):

Eq. (178) $S = P + jQ$

$S = 102.0\ MW + j83.2\ Mvar$

$S = 131.6\angle 39.2°\ MVA$

Primary impedance (Z_{pri}):

Eq. (179) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$Z_{pri} = 904.4\angle 39.2°\ \Omega$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$P = 3 \times 40\ MVA \times 0.85$

$P = 102.0\ MW$

Reactive Power output (Q):

Eq. (184) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q = 83.2\ Mvar$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $V_{nom} = 1.0\ p.u. \times V_{nom}$

$V_{bus} = 1.0 \times 345\ kV$

$V_{bus} = 345\ kV$

Apparent power (S):

Eq. (186) $S = P + jQ$

Example Calculations: Options 18 and 19

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC 025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017
Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period	October 30, 2017 through December 14, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-~~1~~2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~, except that Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

~~6.1. **Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

~~6.1.~~ **Compliance Enforcement Authority**

1.1. ~~As defined in the NERC Rules of Procedure,~~: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise

[3] Interim Report ~~Interim Report:~~: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf~~)~~).

designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. **Evidence Retention**: The following evidence retention ~~periods~~period(s) 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 Compliance Enforcement Authority ~~(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 ~~Generator Owner, Transmission Owner, and Distribution Provider~~applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~CEA~~Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.~~

~~6.2. Compliance Monitoring and Assessment Processes~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~6.3. Additional Compliance Information~~

~~None~~

~~Table of Compliance Elements~~

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-Term Planning~~	~~High~~	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

Deleted Cells

Deleted Cells

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	Standards Committee acceptance of the Standards Authorization Request	Project 2016-04
2	TBD	Adopted by NERC Board of Trustees	Revised
2	TBD	FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in ~~3~~4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads~~.),~~), the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				
	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on generator-side~~	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor

Merged Cells

Inserted Cells

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	~~of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~	**OR**		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) ~~– installed on generator-side of the GSU transformer~~	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.
[7] If the relay is installed on the high-side of the GSU transformer use, Option 15.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Pickup Setting Criteria
	~~If the relay is installed on the high-side of the GSU transformer use Option 15~~	8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system ~~– installed on generator-side~~	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[8] If the relay is installed on the high-side of the GSU transformer use, Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
	~~of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~	9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51)~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
~~Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)~~	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system ~~– installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 19[11]~~	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		

Merged Cells

[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	side terminals of the UAT, for which operation of the relay will cause the associated generator to trip~~.~~	13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				
~~A different application starts on the next page~~				
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 7~~	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or phase time overcurrent relay (e.g., 51)~~—installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

[13] If the relay is installed on the generator-side of the GSU transformer, use Option 8.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based,	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[14] If the relay is installed on the generator-side of the GSU transformer, use Option 9.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant load~~.~~) –connected to synchronous generators	communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~	16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
A different application starts on the next page				
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 10~~	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

[15] If the relay is installed on the generator-side of the GSU transformer, use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
generating plant loads~~,~~) –connected to asynchronous generators only (including inverter-based installations)	**The same application continues on the next page with a different relay type**			

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or Phase time overcurrent relay (e.g., 51)~~— installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 11~~	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or Phase directional time overcurrent relay (e.g., 67)~~— installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 12~~	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

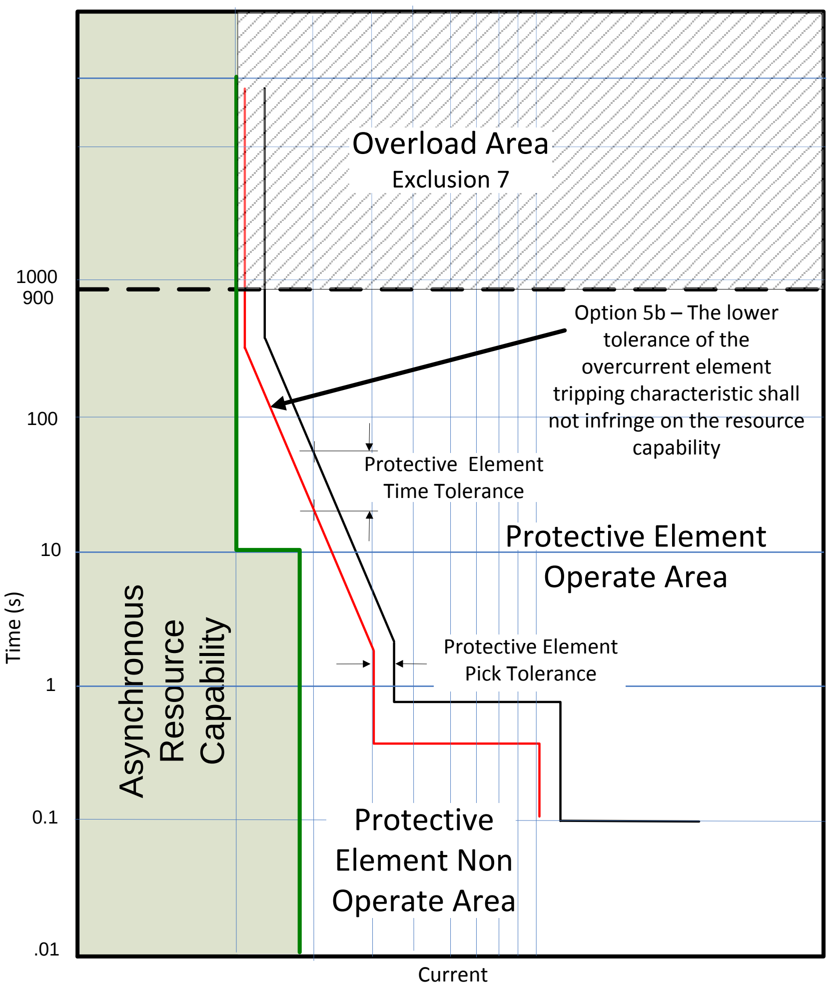


Figure A
This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination~~"Power Plant and Transmission System Protection Coordination,"~~," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed

[18] http://www.nerc.com/~~docs/pc/spctf/~~comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20 Gen%20Prot%~~20Coord%20Rev1%20Final%2007-30-2010~~20Coordination%20Technical%20Reference%20Document.pdf.

within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance ~~is~~are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator

interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

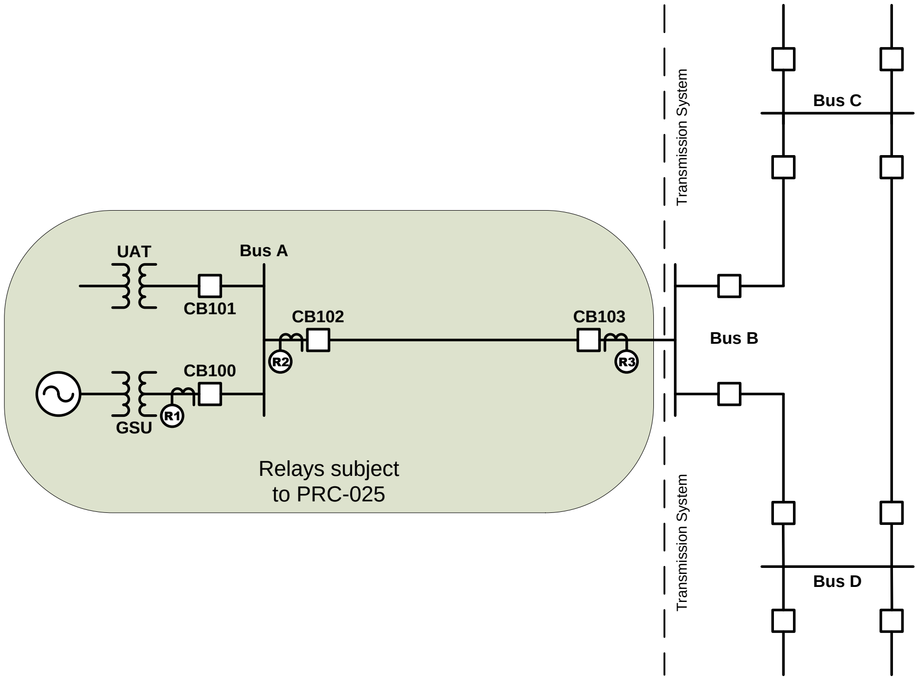
Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case,~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable ~~responsible entity's~~ to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional ~~relay R3 located on breaker CB103 at Bus B looking~~ toward ~~Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not~~the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in ~~this~~the standard~~ or~~. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased ~~transmission system loading~~generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in ~~PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1~~ this standard.~~ PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


Transmission System
Transmission System
Bus C
Bus D
Bus B
UAT
Bus A
CB101
CB102
CB103
CB100
R1
R2
R3
GSU
Relays subject
to PRC-025

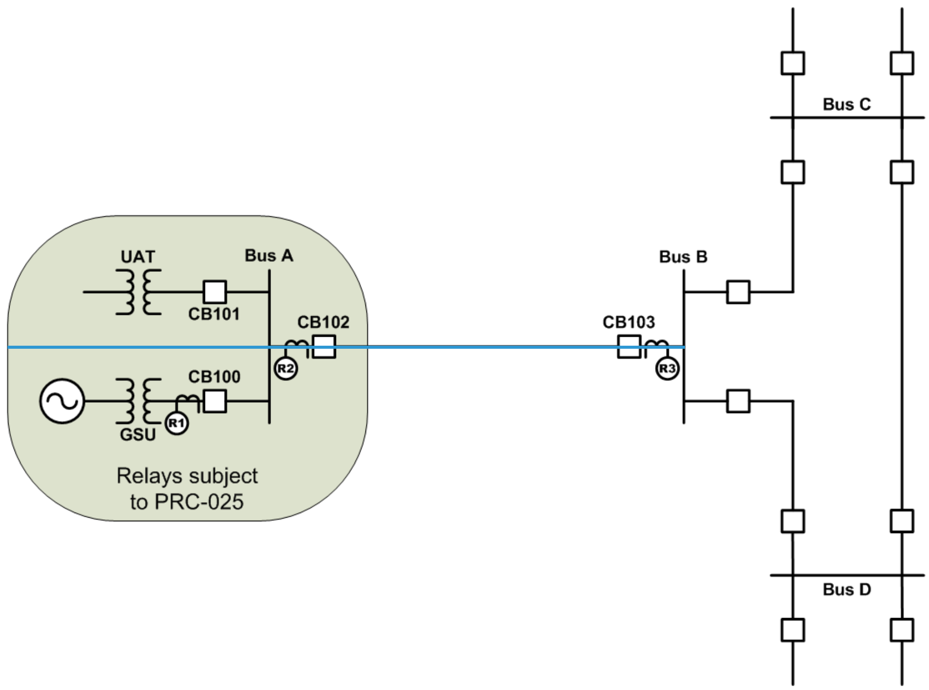


Figure 1~~.~~: Generation exported through a single radial line~~.~~

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

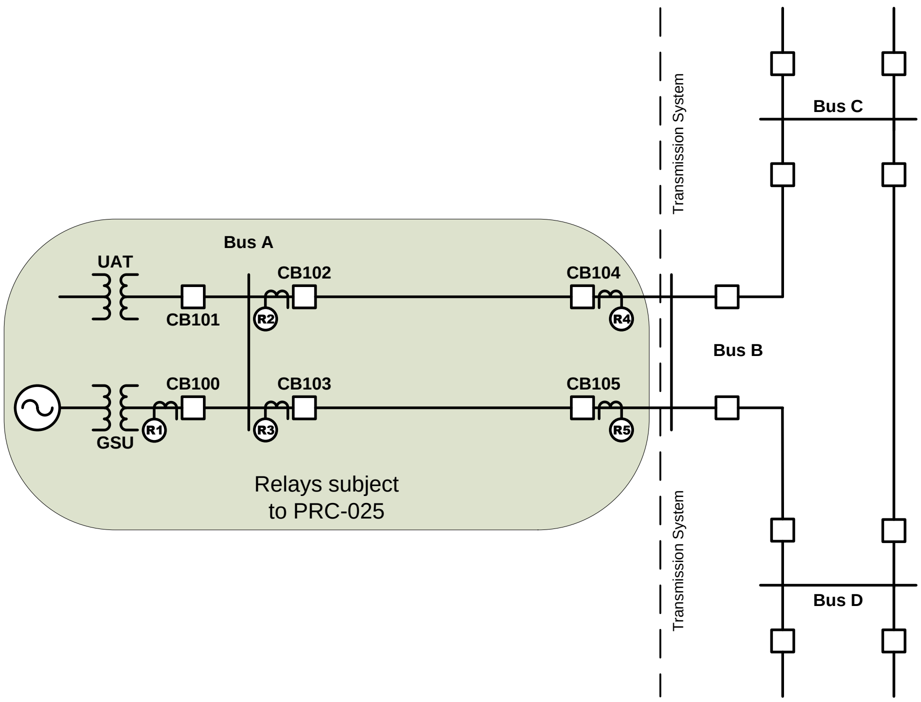


Figure 2~~.~~: Generation exported through multiple radial lines~~.~~

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

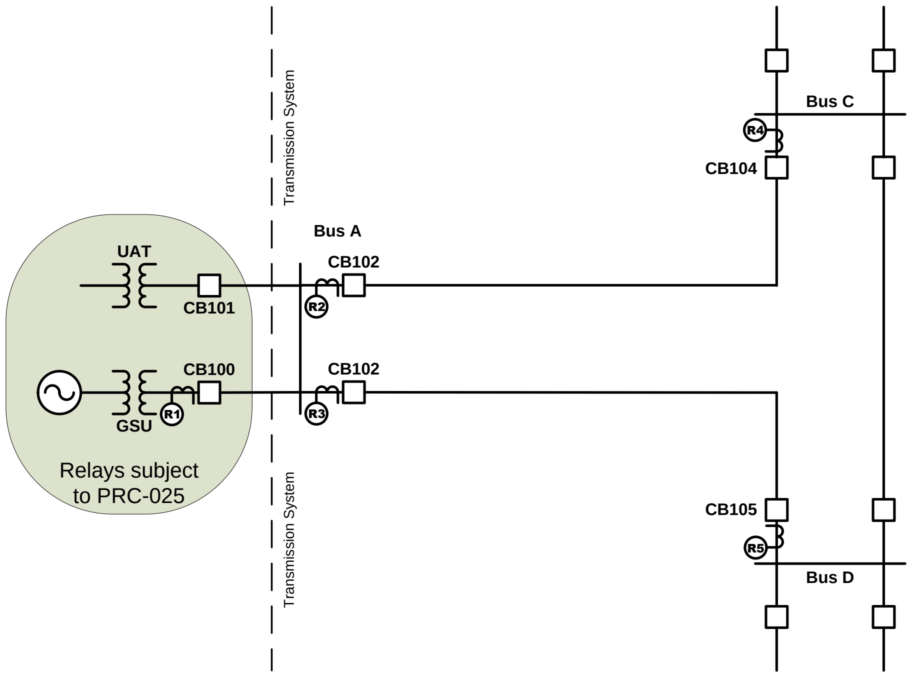


Figure 3~~.~~: Generation exported through a network~~.~~

~~Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.~~

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called

Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

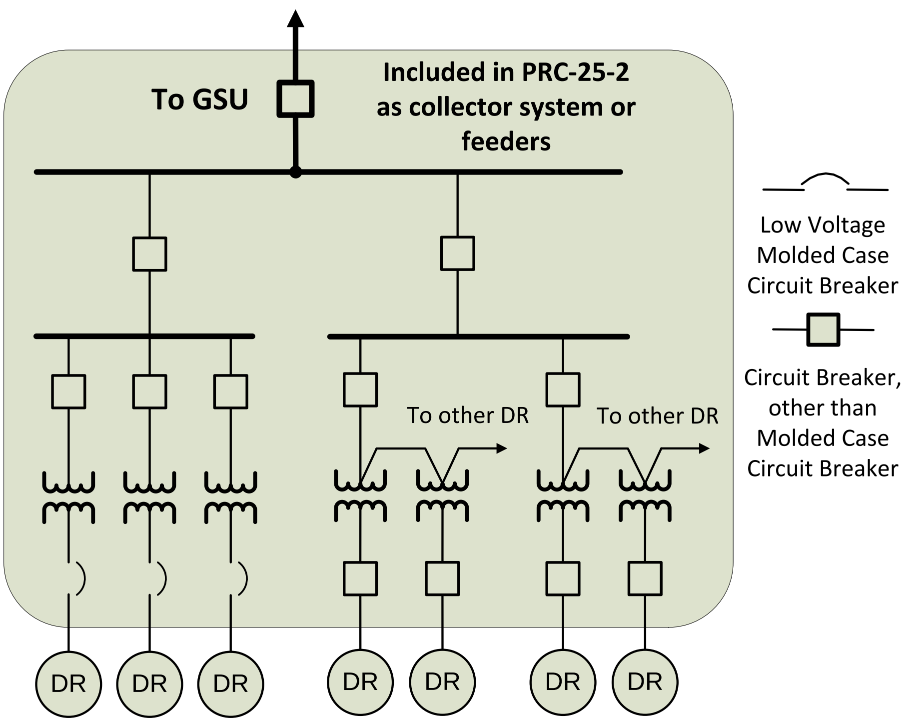


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator

Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure ~~5~~6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage ~~to be used~~at the relay location to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored*

*at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and **normal loading conditions.** However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers **to optimize coordination while still protecting the turbine generator**. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions. **Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.** With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options differ from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options differ from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures ~~4~~5 and ~~5~~6 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

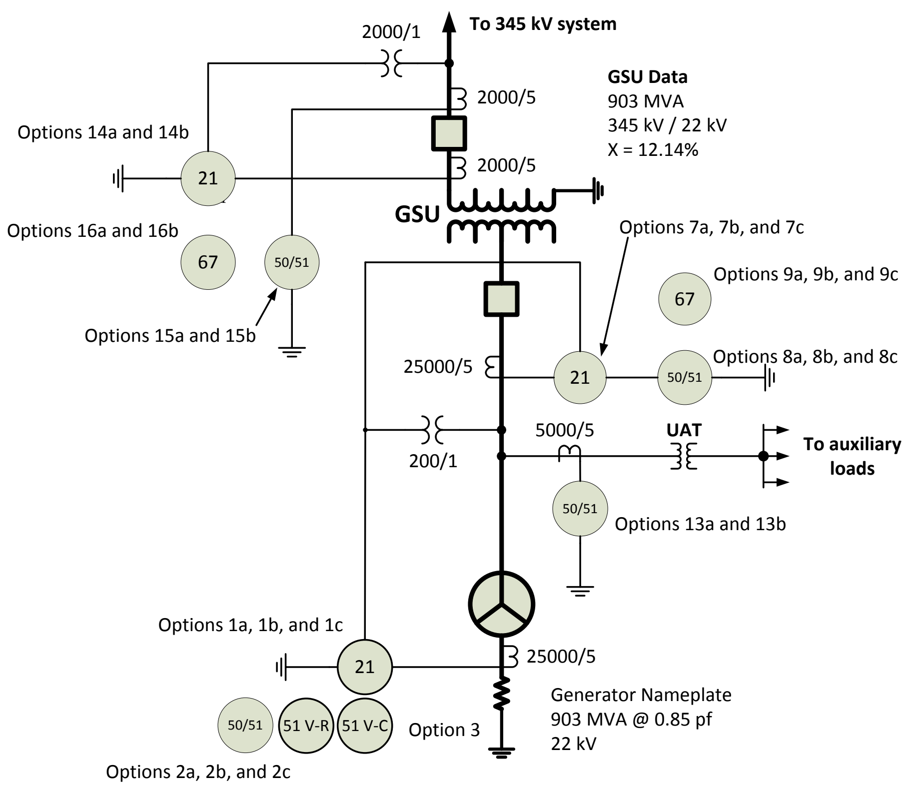


Figure ~~4.~~5: Relay Connection for corresponding synchronous options~~.~~

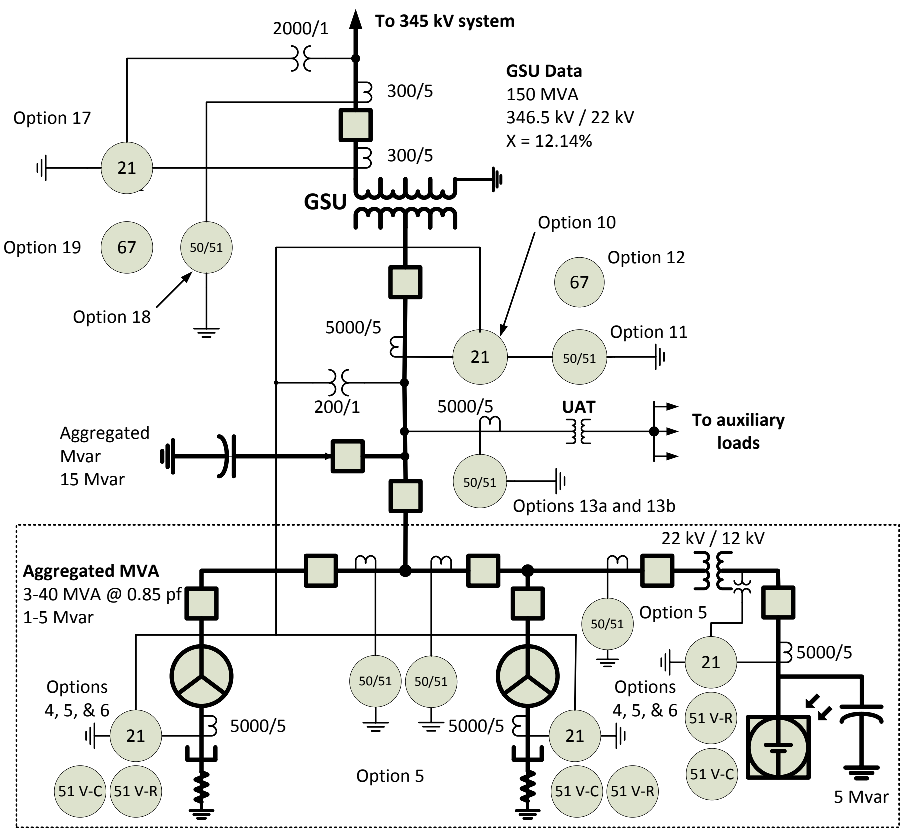


Figure ~~5.~~6: Relay Connection for corresponding asynchronous options including inverter-based installations~~.~~

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~ in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage ~~-~~Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~(“voltage~~-restrained~~”).~~). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage -Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b))

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~("voltage~~-restrained~~")~~.). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying~~of phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~overcurrent~~impedance element ~~overall~~than Options 7a or 7b.

For Options 7a and 7b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 7c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on synchronous generators~~ that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 8c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer of an asynchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay

Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. ~~Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.~~

Refer to the Figures ~~6~~7 and ~~7~~8 below for example configurations:

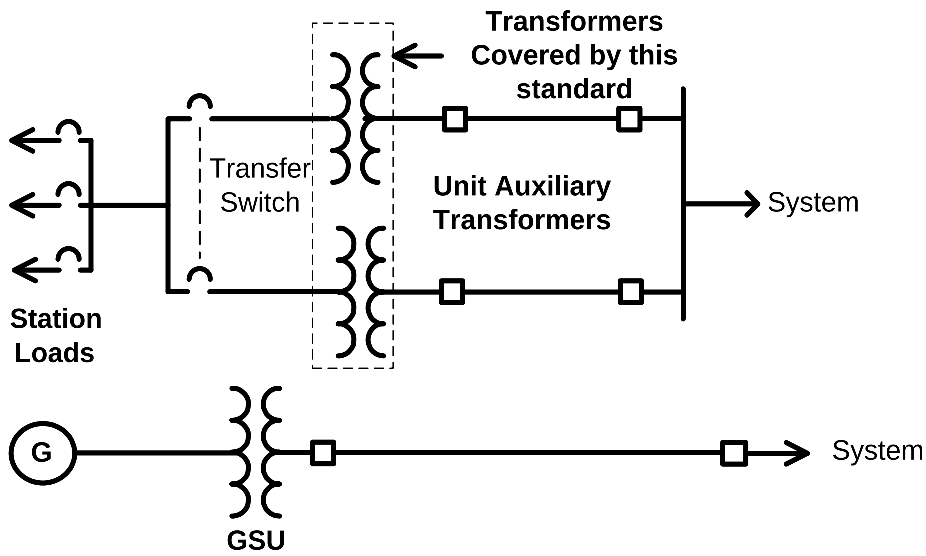


Figure ~~6~~ 7: Auxiliary Power System (independent from generator~~).~~)

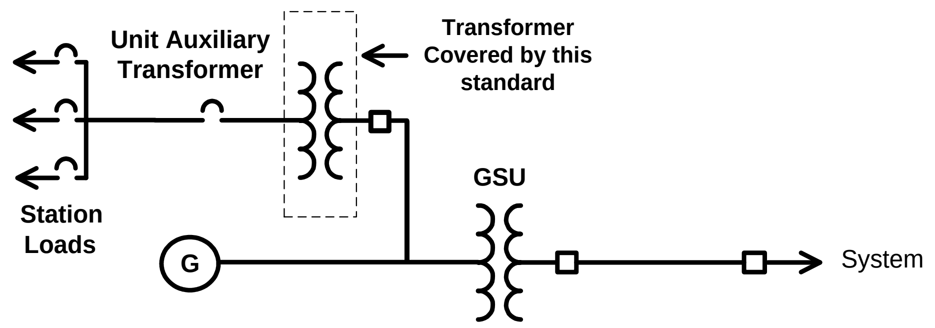


Figure ~~7~~ 8: Typical auxiliary power system for generation units or plants~~.~~

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the ~~entity's~~ relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the

Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional~~ time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~ 85° then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

~~Eq. (15)~~ $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

~~Eq. (17)~~ $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~ 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

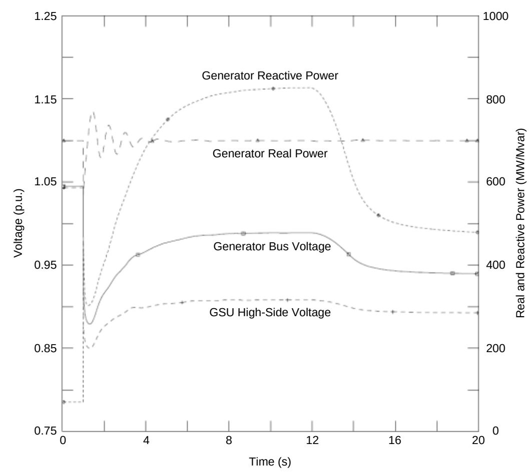
$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

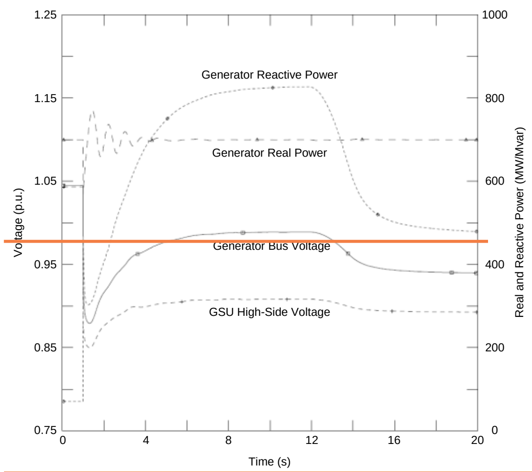
$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\mathrm{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (24) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $Z_{pri} = \dfrac{V^2_{bus\_simulated}}{S^*}$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

Secondary impedance (Z_{sec}):

$$\text{Eq. (26)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

$$\text{Eq. (27)} \quad Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

$$\text{Eq. (28)} \quad Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0^{\circ} - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R – voltage restrained) ~~voltage restrained~~ relay:

Real Power output (P):

$$\text{Eq. (29)} \quad P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

$$\text{Eq. (30)} \quad Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (31)} \quad V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

$$\text{Eq. (32)} \quad S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

$$\text{Eq. (33)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

Example Calculations: Option 2a

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R – voltage restrained) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (*MVA_{base}*).

Real Power output (P):

Eq. (38)
$$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39)
$$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40)
$$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~ Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\, p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

Example Calculations: Option 2b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\, MVA}{1.73 \times 21.90\, kV}$$

$$I_{pri} = 35553\, A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\, A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\, A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

Example Calculations: Option 2b

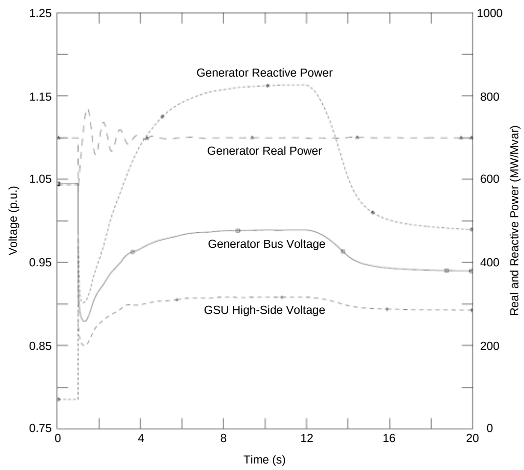
$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



Example Calculations: Option 2c

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.~~

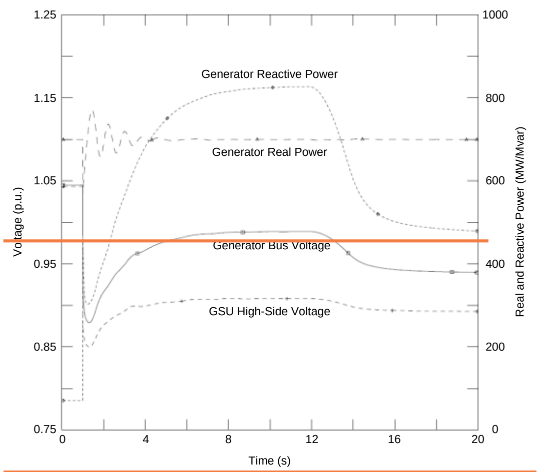
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Example Calculations: Option 2c

Primary current (I_{pri}):

$$\text{Eq. (51)} \quad I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

$$\text{Eq. (52)} \quad I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

$$\text{Eq. (53)} \quad I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) ~~– voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$\text{Eq. (54)} \quad V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Options 3 and 6

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Example Calculations: Option 4

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $Z_{\sec limit} = \frac{Z_{sec}}{130\%}$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Example Calculations: Option 4

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~– voltage-restrained~~ relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 5a

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option 5b

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

~~This~~ These examples represent~~s~~ the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

~~Real Power output (P_{sync}):~~

Real Power output (P_{sync}):

Eq. (~~71~~77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83)
$$V_{gen} = 0.95\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84)
$$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85)
$$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86)
$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

Example Calculations: Options 7a and 10

$$Z_{sec} = 6.32\angle 56.8°\,\Omega$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~ 84 to satisfy the margin requirements in Options 7a and 10:

Eq. (~~81~~87)
$$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\ \angle 56.8°\,\Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\ \angle 56.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~82~~88)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent~~s~~ the simplest calculation for synchronous generators applying a phase time overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89)
$$P = GEN_{Synch\_nameplate} \times pf$$

Example Calculations: Options 8a and 9a

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~84~~90) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (~~86~~92) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~87~~93) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Example Calculations: Options 8a and 9a

Secondary current (I_{sec}):

Eq. (~~88~~94) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent~~s~~ a more ~~complex~~ precise calculation for synchronous generators applying a phase time overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~90~~96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~91~~97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Options 8b and 9b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98)
$$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (~~93~~99)
$$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (~~94~~100)
$$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~ Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Options 8b and 9b

Eq. (~~96~~102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\, p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (~~98~~104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

Example Calculations: Options 8b and 9b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (~~100~~106)
$$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107)
$$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\, MVA}{1.73 \times 21.90\, kV}$$

$$I_{pri} = 35553\, A$$

Secondary current (I_{sec}):

Eq. (~~102~~108)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\, A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\, A$$

Example Calculations: Options 8b and 9b

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\,A \times 1.15$$

$$I_{\sec limit} > 8.178\,A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represent~~s~~ the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110)
$$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\,MVA \times .85$$

$$P_{Synch} = 767.6\,MW$$

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111)
$$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\,MW$$

$$Q_{Synch} = 1151.3\,Mvar$$

Example Calculations: Options 8a, 9a, 11, and 12

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (~~112~~118)
$$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2^\circ\ MVA$$

Primary current ($I_{pri-async}$):

Eq. (~~113~~119)
$$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2^\circ\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755 \angle -39.2^\circ\ A$$

Secondary current (I_{sec}):

Eq. (~~114~~120)
$$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~ 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98~~118:

Eq. (~~115~~121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A \times 1.00$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

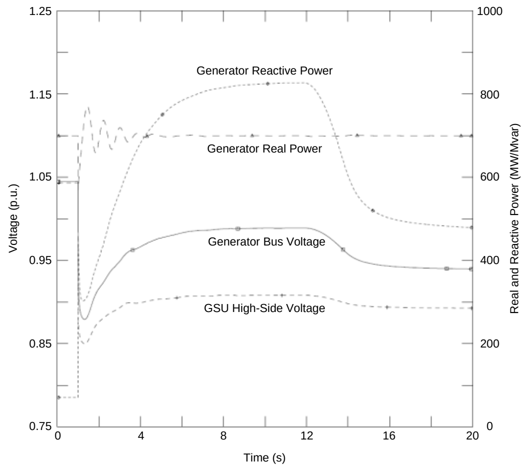
This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~ overcurrent relay~~.~~ (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used ~~as~~since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Formatted Table

Example Calculations: Options 8c and 9c

Formatted Table



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

Formatted Table

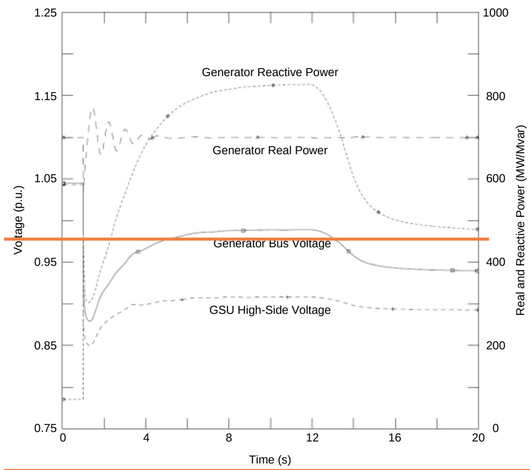
$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 8c and 9c

Formatted Table



Apparent power (S):

Eq. (~~116~~122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (~~117~~123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (~~118~~124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8c and 9c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

$$I_{\sec limit} > I_{sec} \times 115\% \quad \text{Eq. (~~119~~125)}$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option10

This examples represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$P = 3 \times GEN_{Asych\_nameplate} \times pf \quad \text{Eq. (~~120~~126)}$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

$$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right) \quad \text{Eq. (~~121~~127)}$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

$$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio} \quad \text{Eq. (~~122~~128)}$$

Formatted Table

Example Calculations: Option10

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~123~~129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~124~~130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~125~~131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (~~126~~132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

Example Calculations: Option10

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~127~~133)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~ overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~128~~134)
$$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~129~~135)
$$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Options 11 and 12

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~130~~136) $$V_{gen} = 1.0\ p.u.\times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~131~~137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~132~~138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~133~~139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (~~134~~140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle -39.2°\,A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\,A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (~~135~~141)
$$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\,MVA}{1.73 \times 13.8\,kV}$$

$$I_{pri} = 2510.2\,A$$

Secondary current (I_{sec}):

Eq. (~~136~~142)
$$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\,A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (~~137~~143)
$$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\,A \times 1.50$$

$$I_{\sec limit} > 3.77\,A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~138~~144) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~139~~145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high-side~~line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (~~140~~146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (~~141~~147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77^{\circ}\ MVA$$

Example Calculations: Option 14a

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (~~142~~148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle - 52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~143~~149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (~~144~~150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~145~~151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

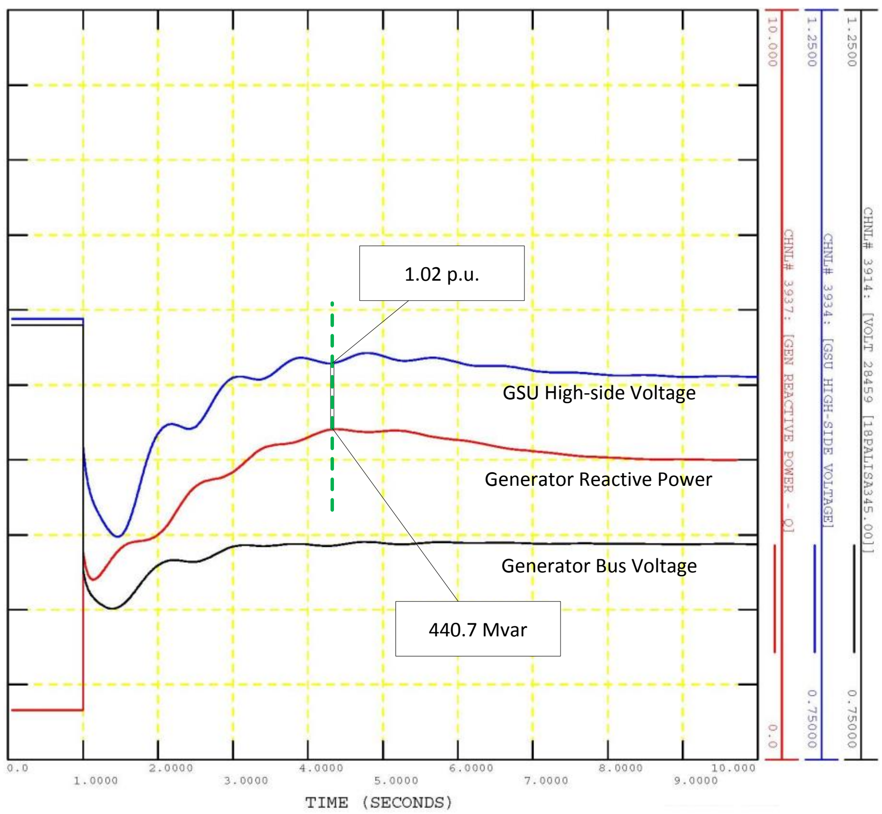
Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that~~connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and ~~high-side bus voltage~~coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~these values will correspond to the lowest apparent impedance~~.~~ at the relay location. The corresponding ~~high-side bus~~simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

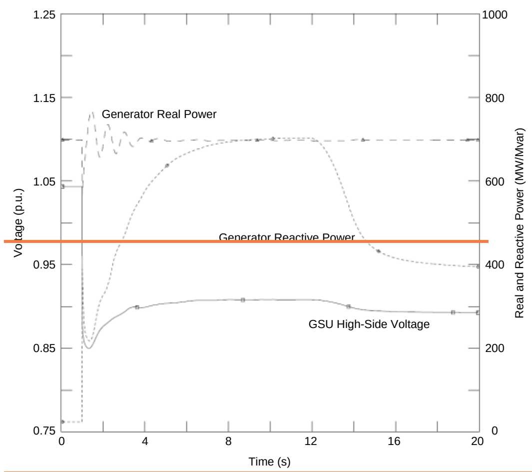
$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

Formatted Table

Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~152) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (~~147~~153) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

Eq. (~~148~~154)
$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\,\Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\,\Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\,\Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (~~149~~155)
$$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\,\Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\,\Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~150~~156)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20\,\Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\,\Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\,\Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation~~relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~installed on the high-side of the GSU transformer~~.~~, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~directional toward the Transmission system~~–~~ installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~151~~157)

$$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~152~~158)

$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

Example Calculations: Options 15a and 16a

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Formatted Table

Eq. (~~153~~159) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (~~154~~160) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (~~155~~161) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (~~156~~162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 15b:

Formatted Table

Eq. (~~157~~163) $$I_{sec\,limit} > I_{sec} \times 115\%$$

Example Calculations: Options 15a and 16a

$$I_{\sec limit} > 5.701 \angle -52.8° \, A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle -52.8° \, A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Reactive Power output (Q):

Eq. (165) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6 \, MW$$

$$Q = 921.12 \, Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $V_{bus\_remote\_substation} = 0.85 \, p.u. \times V_{nom}$

$$V_{bus\_remote\_substation} = 0.85 \times 345 \, kV$$

$$V_{bus\_remote\_substation} = 293.25 \, kV$$

Apparent power (S):

Eq. (167) $S = P_{Synch\_reported} + jQ$

$$S = 700.0 \, MW + j921.12 \, Mvar$$

$$S = 1157 \angle 52.8° \, MVA$$

Primary current (I_{pri}):

Eq. (168) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$

Formatted Table

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle - 52.8° \ MVA}{1.73 \times 293.25 \ kV}$$

$$I_{pri} = 2280.6\angle - 52.8° \ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8° \ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle - 52.8° \ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701 \angle - 52.8° \ A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle - 52.8° \ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation.

Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~installed on the high-side of the GSU transformer~~.~~, including relays at the remote end of the line.

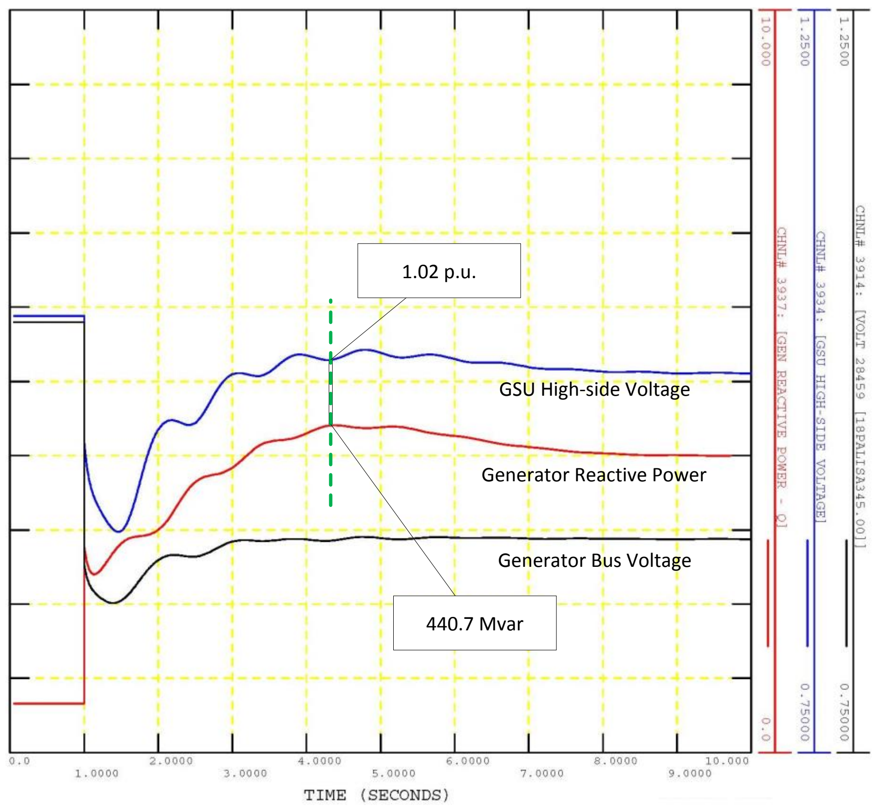
Option 16b represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~directional toward the Transmission system~~–~~ and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

~~This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.~~

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side ~~bus voltage~~of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~these values will correspond to the lowest apparent impedance~~.~~ at the relay location. The corresponding ~~high-side bus~~simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

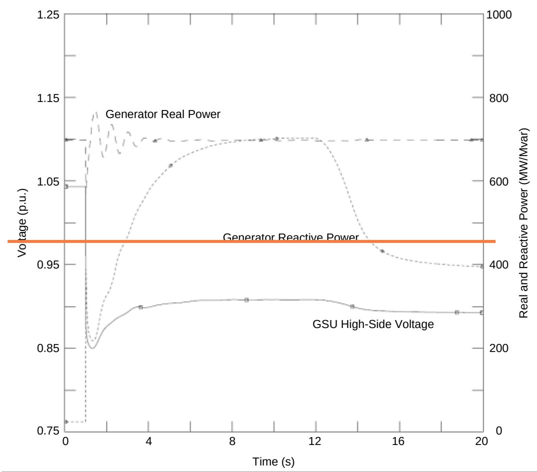
Formatted: Centered

Formatted Table

Example Calculations: Options 15b and 16b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~158~~171) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (~~159~~172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Example Calculations: Options 15b and 16b

Secondary current (I_{sec}):

Eq. (~~160~~173)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1831.2\angle - 45.1^\circ A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578 \angle - 45.1^\circ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (~~161~~174)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 4.578 \angle - 45.1^\circ A \times 1.15$$

$$I_{\sec limit} > 5.265 \angle - 45.1^\circ A$$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~162~~175)
$$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA\ \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~163~~176)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

Example Calculations: Option 17

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (~~164~~177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (~~165~~178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~166~~179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181)
$$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\,\Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\,\Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (~~169~~182)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\,\Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\,\Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\,\Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation Elements that connect a~~ relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~.

Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that

Example Calculations: Options 18 and 19

are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

$$P = 3 \times GEN_{Asych\_nameplate} \times pf \qquad \text{Eq. } (\cancel{170}183)$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

$$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right) \qquad \text{Eq. } (\cancel{171}184)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

$$V_{nom} = 1.0\ p.u. \times V_{nom} \qquad \text{Eq. } (\cancel{172}185)$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

$$S = P + jQ \qquad \text{Eq. } (\cancel{173}186)$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}} \qquad \text{Eq. } (\cancel{174}187)$$

Example Calculations: Options 18 and 19

$$I_{pri} = \frac{131.6\angle - 39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle - 39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle - 39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle - 39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle - 39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle - 39.2°\ A$$

End of calculations

Rationale~~:~~

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

Rationale for R1~~:~~

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1
Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite Standard

- None

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

This Implementation Plan supersedes and retires the *Implementation Plan PRC-025-1 – Generator Relay Loadability*[1] such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. In drafting this Implementation Plan, the PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the phased-in implementation dates for PRC-025-1. The first U.S. phased-in implementation date for PRC-025-1 of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. phased-in implementation date for PRC-025-1 of October 1, 2021 applies to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities,
- The proposed revisions to Options 14b, 15b, and 16b may give reason for entities to re-evaluate their settings for load-responsive protective relays,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[1] http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_(Clean).pdf

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the later of October 1, 2019 or 12 months after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 – Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the later of October 1, 2021 or 36 months after the effective date of Reliability Standard PRC-025-2, except as noted for the Table 1 Relay Loadability Evaluation Criteria Options listed below

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	**Application and Relay Type**	**Implementation Date**
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V-R – voltage-restrained)[2]	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

[2] Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

<table>
<tr><th>Requirement</th><th>Applicability</th><th>Implementation Date</th></tr>
<tr><td rowspan="2">R1</td><td rowspan="2">Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.</td><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard</td></tr>
<tr><td>Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard</td></tr>
</table>

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

None

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan

Project 2016-04 – Modifications to PRC-025-1
Reliability Standard PRC-025-2

Applicable Standard

- PRC-025-2 – Generator Relay Loadability

Requested Retirement

- PRC-025-1 – Generator Relay Loadability

Prerequisite Standard

- None

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

This Implementation Plan supersedes and retires the *Implementation Plan PRC-025-1 – Generator Relay Loadability*[1] such that entities are not required to implement the requirements in the PRC-025 Reliability Standard until the dates provided herein. In drafting this Implementation Plan, the PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the phased-in implementation dates for PRC-025-1. The first U.S. phased-in implementation date for PRC-025-1 of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. phased-in implementation date for PRC-025-1 of October 1, 2021 applies to load-responsive protective relays where the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The phased-in implementation dates for PRC-025-1,
- The proposed Option 5b reduces the implementation burden to the applicable entities,
- The proposed revisions to Options 14b, 15b, and 16b may give reason for entities to re-evaluate their settings for load-responsive protective relays,
- A few proposed Option(s) that now include the 50 element, and
- Generator outage cycles.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

[1] http://www.nerc.com/pa/Stand/PRC0251RD/PRC_025_1_Implementation_Plan_2013_06_20_Draft_4_(Clean).pdf

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, the later of October 1, 2019 or 12 months after the effective date of Reliability Standard PRC-025-2, except as noted for the PRC-025-2 – Attachment 1, Table 1 Relay Loadability Evaluation Criteria, Options listed below
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, the later of October 1, 2021 or 36 months after the effective date of Reliability Standard PRC-025-2, except as noted for the Table 1 Relay Loadability Evaluation Criteria Options listed below

Phased-in implementation of specific Table 1 Relay Loadability Evaluation Criteria Options		
Option	**Application and Relay Type**	**Implementation Date**
Option 5b	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying any phase overcurrent relay (e.g., 51, or 51V-R – voltage-restrained)[2]	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

[2] Phased-in implementation of the phase overcurrent relay 50 element is provided under Options 5a and 5b.

Options 2a, 2b, and 2c (50 element only)	Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 5a and 5b (50 element only)	Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources applying, specifically the phase overcurrent relay 50 element	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 8a, 8b, and 8c (50 element only)	Generator step-up transformer(s) connected to synchronous generators applying, specifically the phase overcurrent relay 50 element installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 11 (50 element only)	Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations) applying, specifically the phase	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2

	overcurrent 50 element – installed on generator-side of the GSU transformer	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Options 13a and 13b (50 element only)	Unit auxiliary transformer(s) (UAT) applying, specifically the phase overcurrent 50 element applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months after the effective date of Reliability Standard PRC-025-2
Option 14b	Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase distance relay (e.g., 21) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 15b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2

	the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators applying a phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or phase time overcurrent relay (e.g., 51)	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2
Option 16b	Relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant load.) – connected to synchronous generators applying Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 24 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 48 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

PRC-025-1

Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

None

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-04 Modifications to PRC-025-1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. 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 Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for 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 Guidelines for Violation Risk Factors

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

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

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

The FERC 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 for PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF Justifications for PRC-025-1, R1	
Proposed VRF	**High**
Guideline 4- Consistency with NERC Definitions of VRFs	The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

VSLs for PRC-025-2, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications for PRC-025-2, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.

VSL Justifications for PRC-025-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be “Severe” in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.

VSL Justifications for PRC-025-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on “an applied load-responsive protective relay” in accordance with Attachment 1: Relay Settings.

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-04 Modifications to PRC-025-1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in [Project Number and Name or Standard Number]. 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 Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for 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 Guidelines for Violation Risk Factors

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

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

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

The FERC 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 for PRC-025-1, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, 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. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a "High" VRF.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a "High" VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF Justifications for PRC-025-1, R1	
Proposed VRF	**High**
Guideline 4- Consistency with NERC Definitions of VRFs	The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

VSLs for PRC-025-2, R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

VSL Justifications for PRC-025-2, R1	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.

VSL Justifications for PRC-025-2, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.

VSL Justifications for PRC-025-2, R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

Standards Announcement

Project 2016-04 Modifications to PRC-025-1

Final Ballot Open through January 18, 2018

Now Available

A final ballot for **PRC-025-2 – Generator Relay Loadability** is open through **8 p.m. Eastern, Thursday, January 18, 2018.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log in and submit their votes by accessing the Standards Balloting & Commenting System (SBS) here. If you experience issues navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Scott Barfield-McGinnis (via email) or at (404) 446-9689.

Atlanta, GA 30326
404-446-2560 | www.nerc.com

BALLOT RESULTS

Ballot Name: 2016-04 Modifications to PRC-025-1 PRC-025-2 FN 3 ST
Voting Start Date: 1/9/2018 7:11:48 AM
Voting End Date: 1/18/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 258
Total Ballot Pool: 312
Quorum: 82.69
Weighted Segment Value: 89.46

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	81	1	62	0.954	3	0.046	0	8	8
Segment: 2	4	0.2	2	0.2	0	0	0	1	1
Segment: 3	73	1	50	0.862	8	0.138	0	4	11
Segment: 4	17	1	8	0.727	3	0.273	0	0	6
Segment: 5	74	1	45	0.865	7	0.135	0	6	16
Segment: 6	50	1	33	0.917	3	0.083	0	3	11
Segment: 7	2	0.1	1	0.1	0	0	0	0	1
Segment: 8	3	0.3	3	0.3	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	7	0.7	7	0.7	0	0	0	0	0
Totals:	312	6.4	212	5.725	24	0.675	0	22	54

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Negative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Basin Electric Power Cooperative	David Rudolph		Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Affirmative	N/A
1	CMS Energy - Consumers Energy Company	James Anderson		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Abstain	N/A
1	Dairyland Power Cooperative	Robert Roddy		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Affirmative	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Michael Shaw		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Memphis Light, Gas and Water Division	Allan Long		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		None	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Abstain	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Ohio Valley Electric Corporation	Scott Cunningham		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Peak Reliability	Scott Downey		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		None	N/A
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		None	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Abstain	N/A
3	AEP	Aaron Austin		Affirmative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Basin Electric Power Cooperative	Jeremy Voll		Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		None	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Leesburg	Chris Adkins	Brandon McCormick	Negative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Abstain	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Duke Energy	Lee Schuster		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Eversource Energy	Mark Kenny		None	N/A
3	Exelon	John Bee		Negative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	N/A
3	Georgia System Operations Corporation	Scott McGough		Negative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	Jessica Tucker	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Affirmative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Rutherford EMC	Tom Haire		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Silicon Valley Power - City of Santa Clara	Val Ridad		None	N/A
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		None	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Janelle Marriott Gill		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		None	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	City Utilities of Springfield, Missouri	John Allen		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	N/A
4	Georgia System Operations Corporation	Guy Andrews		Negative	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Affirmative	N/A
4	Indiana Municipal Power Agency	Jack Alvey	Scott Berry	None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	Acciona Energy North America	George Brown		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Arkansas Electric Cooperative Corporation	Moses Harris		None	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Jeanie Doty		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	Basin Electric Power Cooperative	Mike Kraft		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Thomas Rafferty		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Negative	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	Hydro-Qu?bec Production	Junji Yamaguchi		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough		Negative	N/A
5	Lakeland Electric	Jim Howard		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Affirmative	N/A
5	Luminant - Luminant Generation Company LLC	Alshare Hughes		None	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	NB Power Corporation	Laura McLeod		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Don Schmit		Affirmative	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NextEra Energy	Allen Schriver		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Abstain	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Negative	N/A
5	Omaha Public Power District	Mahmood Safi		Affirmative	N/A
5	Ontario Power Generation Inc.	David Ramkalawan		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Mike Haynes		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	SunPower	Bradley Collard		None	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Talen Generation, LLC	Matthew McMillan		Negative	N/A
5	TECO - Tampa Electric Co.	R James Rocha		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Basin Electric Power Cooperative	Paul Huettl		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jim Flucke	Douglas Webb	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Shivaz Chopra		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Abstain	N/A
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		None	N/A
6	Omaha Public Power District	Joel Robles		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Affirmative	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		None	N/A
6	Southern Indiana Gas and Electric Co.	Brad Lisembee		None	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Talen Energy Marketing, LLC	Jennifer Hohenshilt		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Exxon Mobil	Jay Barnett		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 312 of 312 entries

Previous 1 Next

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017
Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period	October 30, 2017 through December 14, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

---

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

   During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf).

and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. **Evidence Retention:** The following evidence retention period(s) 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 Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, “Considerations for Power Plant and Transmission System Protection Coordination,” technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition.” (Date of Publication: March 2016)

IEEE C37.102-2006, “IEEE Guide for AC Generator Protection.” (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04
2	TBD	Adopted by NERC Board of Trustees	Revision
2	TBD	FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction
This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators
Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers
Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>Setting Criteria</th></tr>
<tr><td rowspan="6">Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators</td><td rowspan="5">Phase distance relay (e.g., 21) – directional toward the Transmission system</td><td>7a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>7b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>7c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.

bility Evaluation Criteria			
Relay Type	**Option**	**Bus Voltage[5]**	**Setting Criteria**
nase overcurrent lay (e.g., 50 or 1)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
The same application continues on the next page with a different relay type			

bility Evaluation Criteria

Relay Type	Option	Bus Voltage[5]	Setting Criteria
	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
hase directional vercurrent relay .g., 67) – rectional toward e Transmission stem	9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51)[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.
[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

bility Evaluation Criteria			
Relay Type	Option	Bus Voltage[5]	Setting Criteria
hase stantaneous vercurrent upervisory ement (e.g., 50) – sociated with urrent-based, ommunication-sisted schemes here the scheme capable of ipping for loss of ommunications nd/or phase time vercurrent relay .g., 51)	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

The same application continues on the next page with a different relay type

bility Evaluation Criteria			
Relay Type	Option	Bus Voltage[5]	Setting Criteria
nase directional stantaneous vercurrent upervisory ement (e.g., 67) – sociated with urrent-based, ommunication-sisted schemes here the scheme capable of ipping for loss of ommunications rectional toward e Transmission stem and/or nase directional me overcurrent lay (e.g., 67) – rectional toward e Transmission stem	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

bility Evaluation Criteria			
Relay Type	Option	Bus Voltage[5]	Setting Criteria
hase distance lay (e.g., 21) – rectional toward e Transmission stem	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

The same application continues on the next page with a different relay type

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[17] If the relay is installed on the generator-side of the GSU transformer, use Option 12.

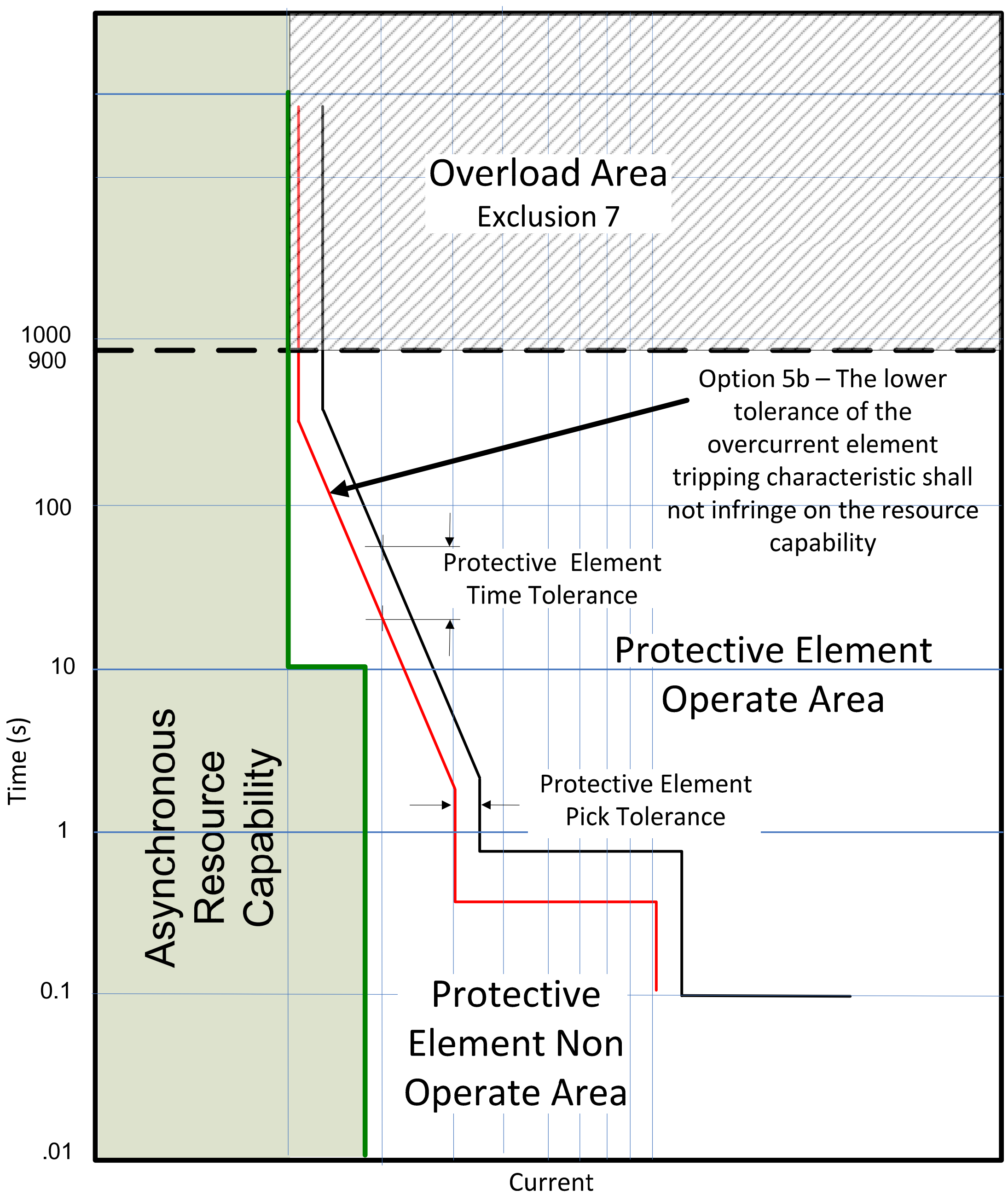


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

[18] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

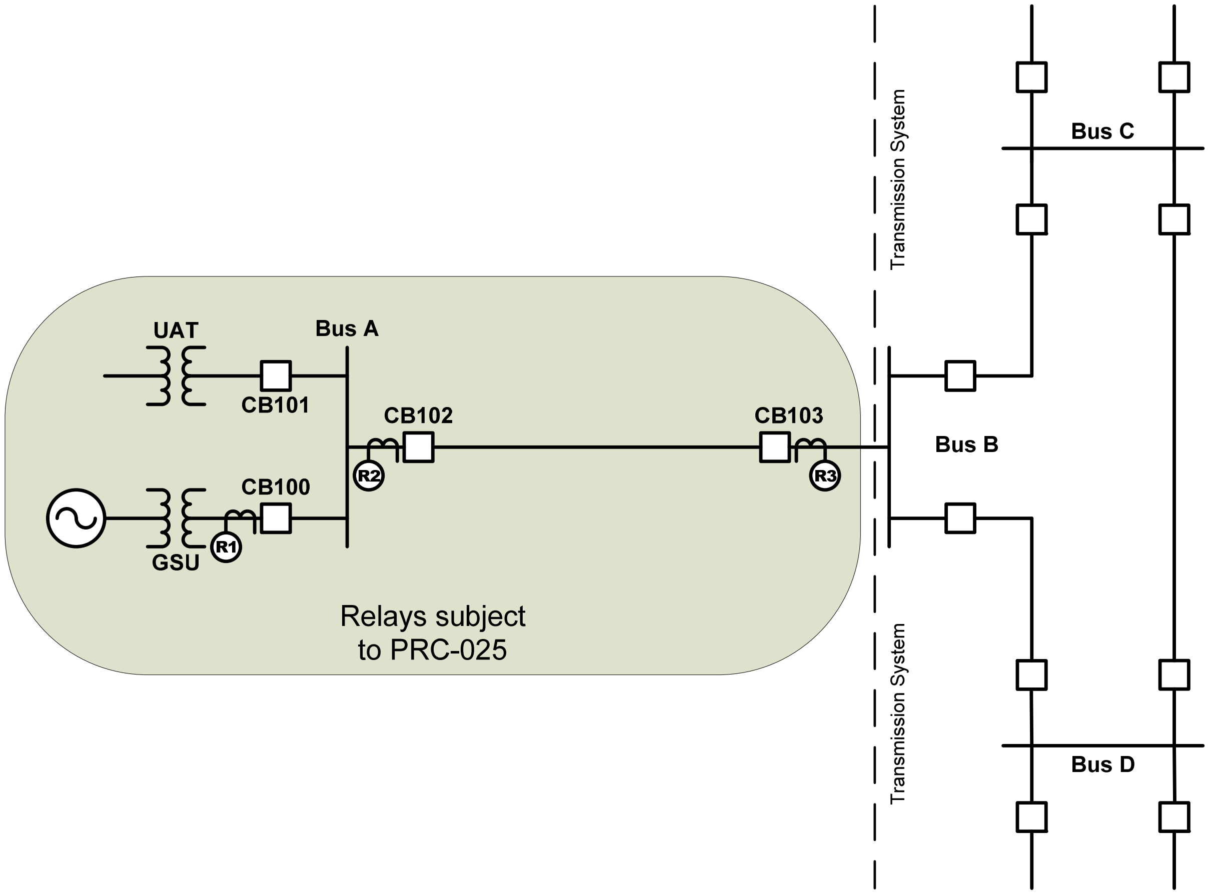


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

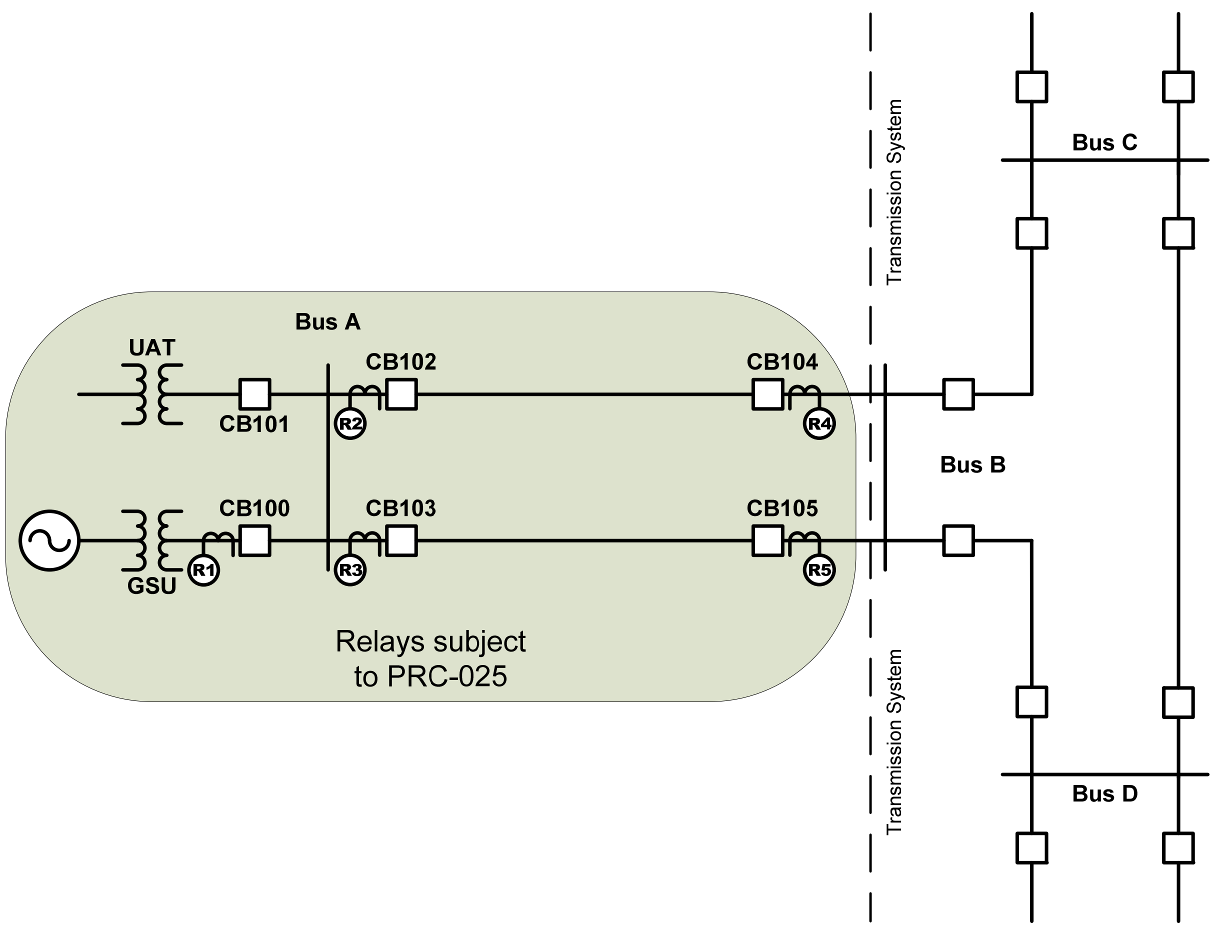


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity’s loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

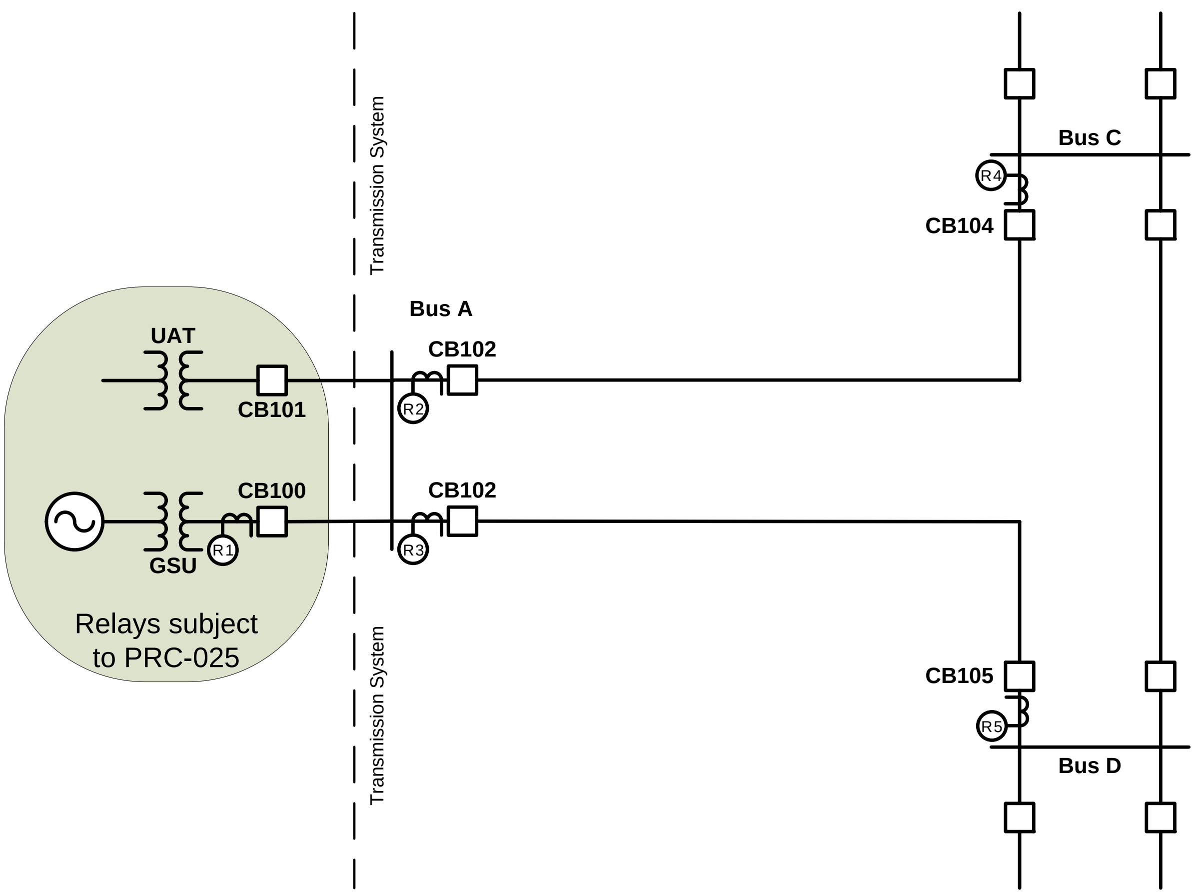


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system” or “feeders”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

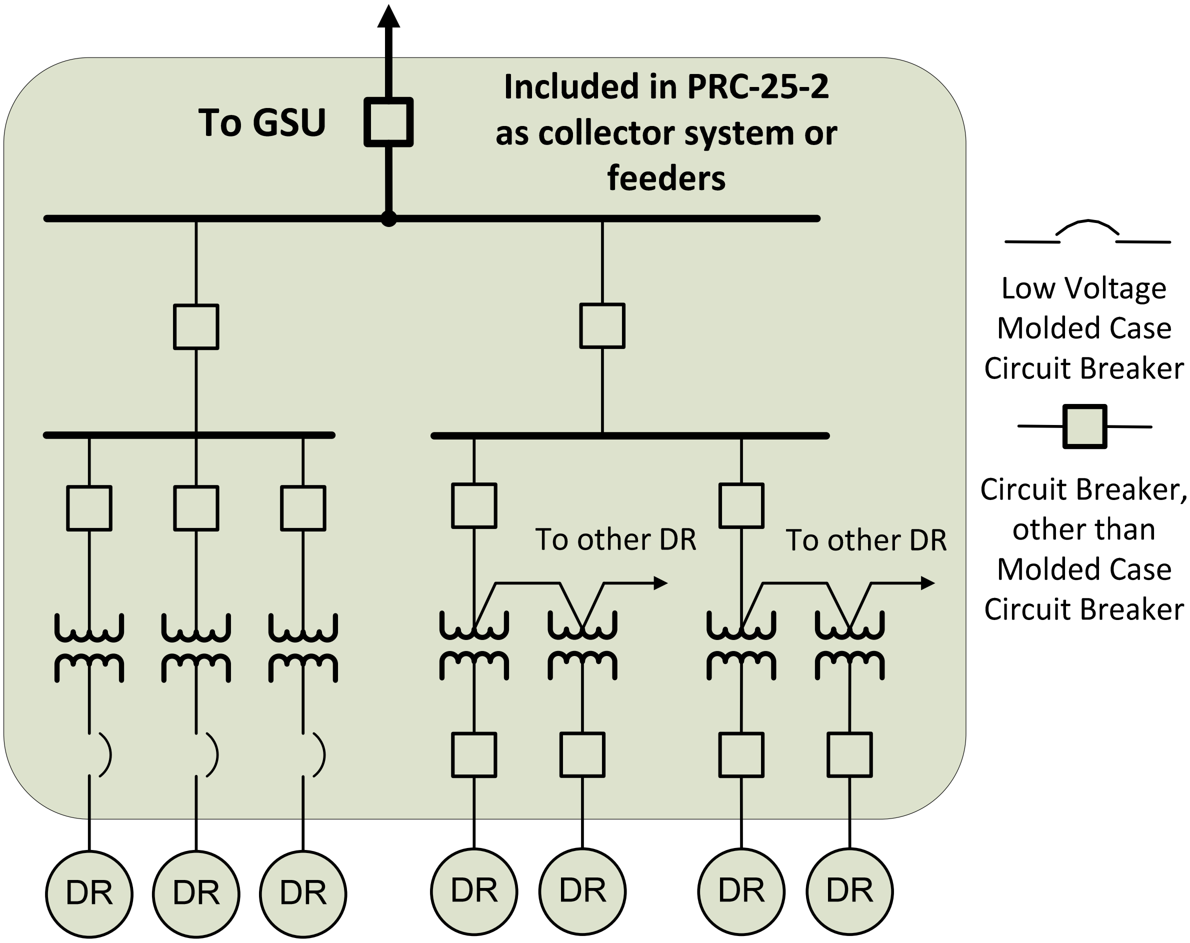


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column “Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

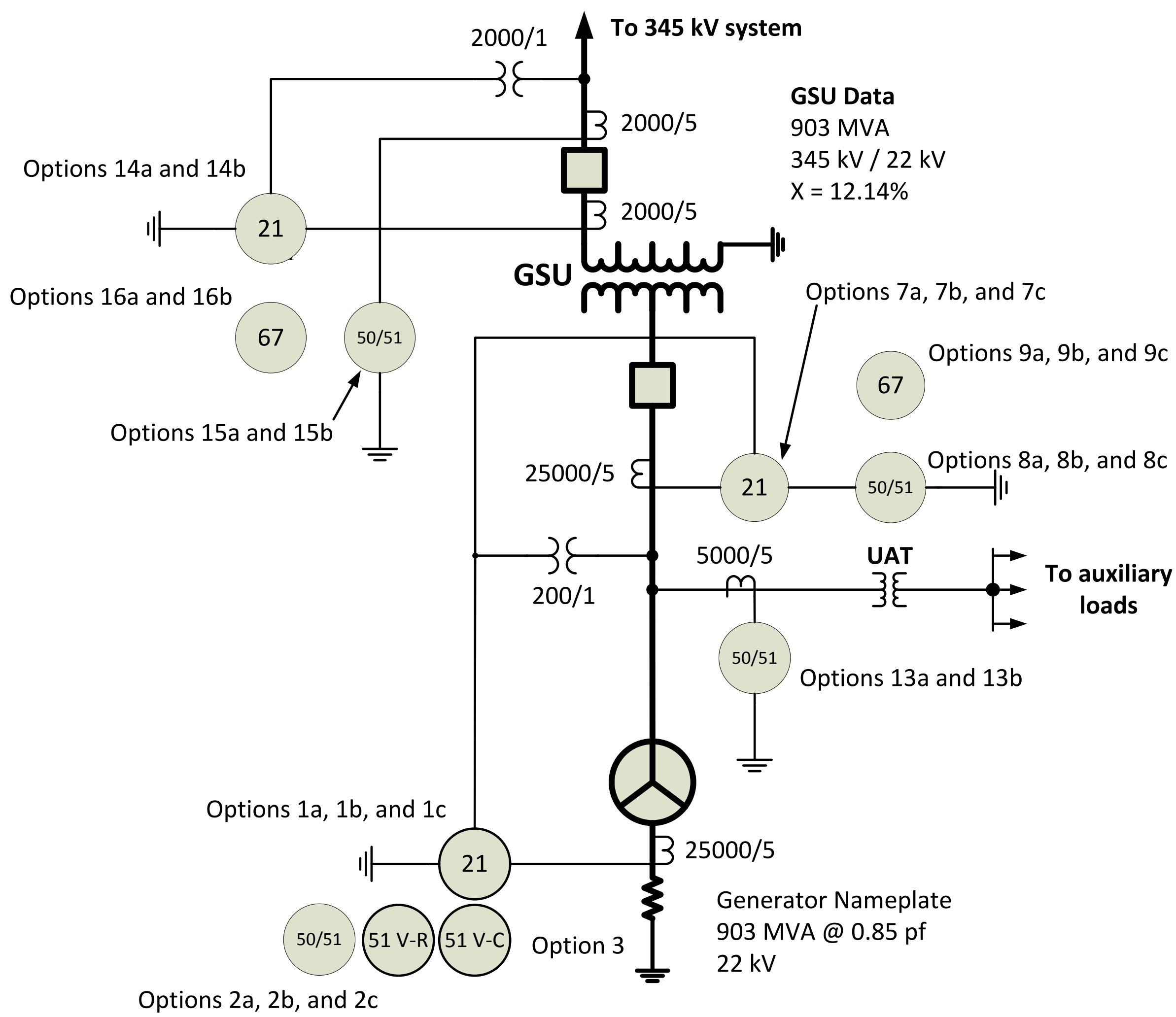


Figure 5: Relay Connection for corresponding synchronous options

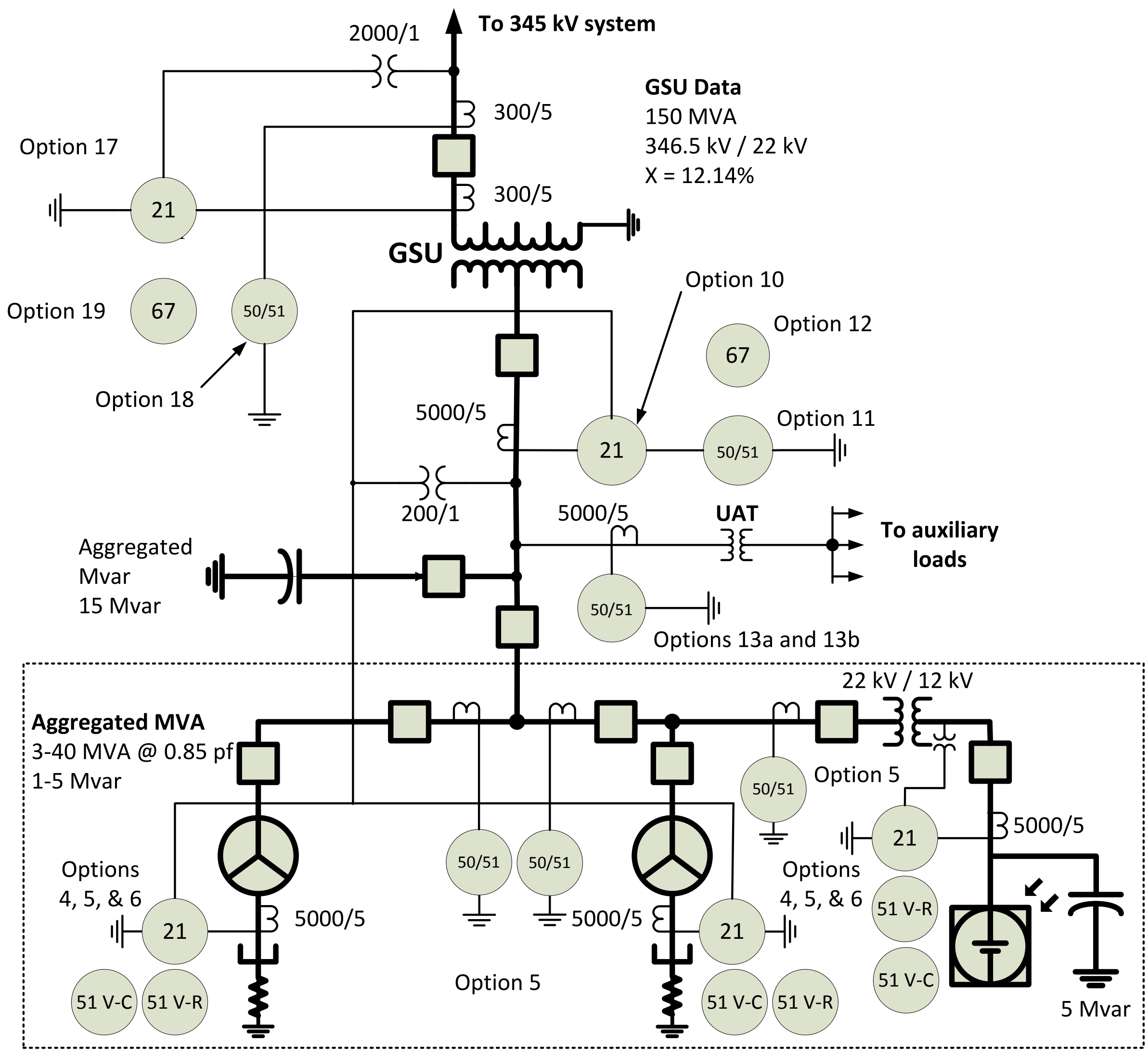


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer’s turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

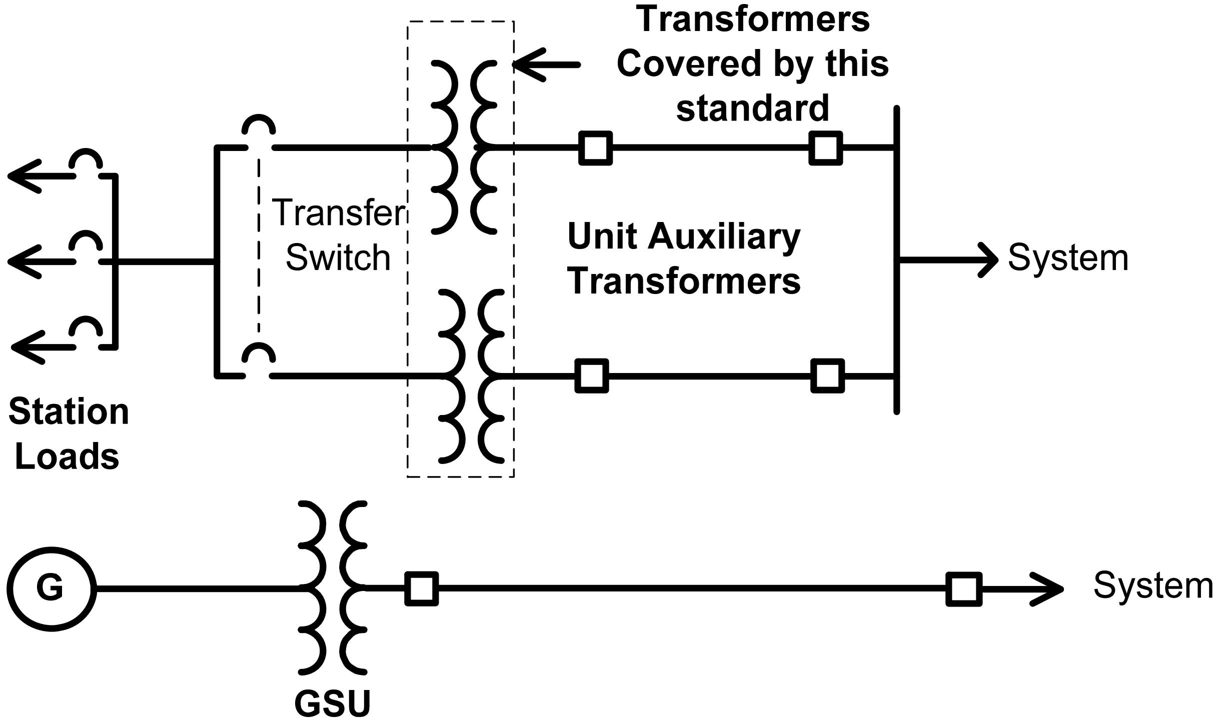


Figure 7: Auxiliary Power System (independent from generator)

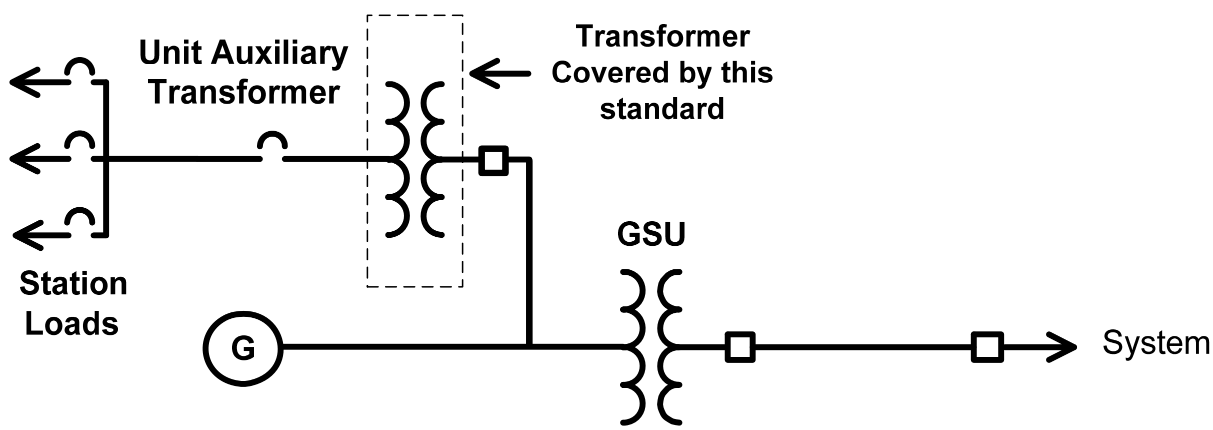


Figure 8: Typical auxiliary power system for generation units or plants

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at

the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT high-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7° \ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7° \ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7° \ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7° \ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7° \ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7° \ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873 \ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873 \ \Omega}{0.896}$$

$$Z_{max} < \ 7.793\angle 85.0° \ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (*MVA_{base}*):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

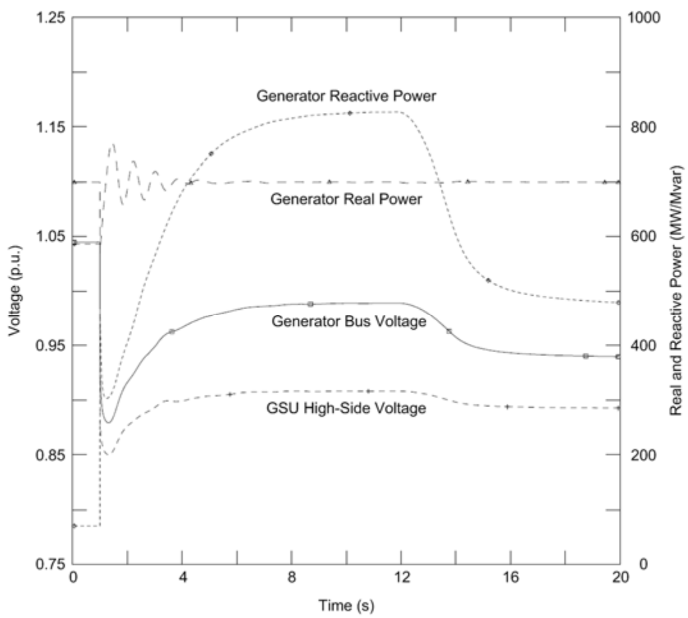
$$Z_{max} < \frac{7.74\,\Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\,\Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Option 2b

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

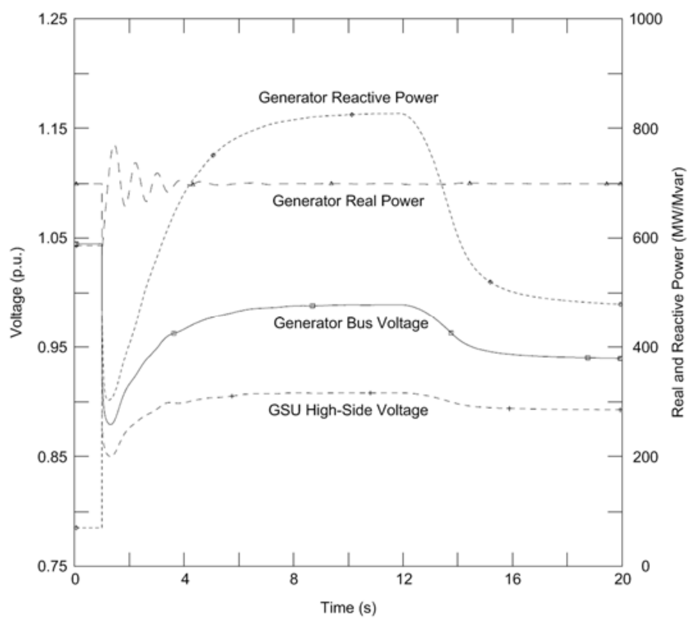
$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$$I_{\text{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $V_{setting} < V_{gen} \times 75\%$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $P = GEN_{Asych\_nameplate} \times pf$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) +\ 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30\ \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle - 56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \ \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0° \ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S_{Synch}^{*}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7° \, A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \, MVA \times 0.85$$

$$P_{Asynch} = 102.0 \, MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \, Mvar + 5 \, Mvar + (3 \times 40 \, MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \, Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \, kV \times \left(\frac{22 \, kV}{346.5 \, kV}\right)$$

$$V_{gen} = 20.81 \, kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \, MW + j83.2 \, Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2° \, MVA$$

Primary current ($I_{pri-async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2° \ MVA}{1.73 \ \times 20.81 \ kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \ A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \ A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \ A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \ A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \ A \times 1.00$$

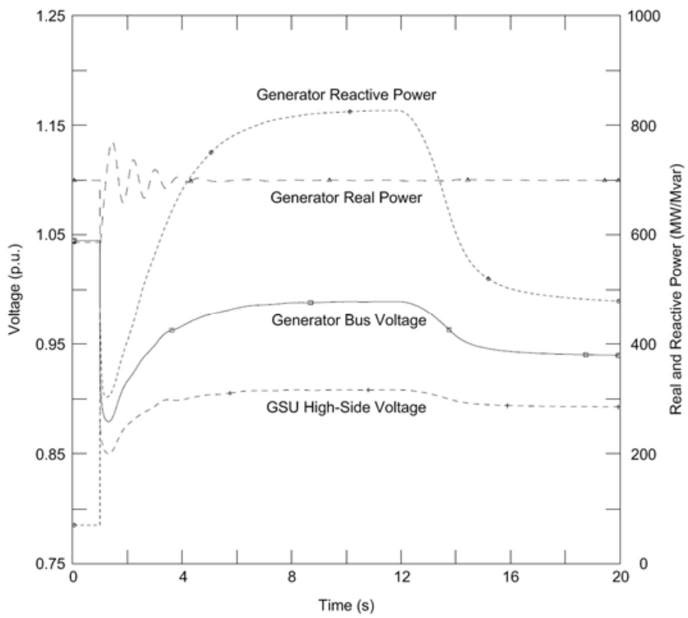
$$I_{\sec limit} > 9.514 \angle -56.8° \ A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{sec\,limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P +\ jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle-39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle-39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = \ GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u.\times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

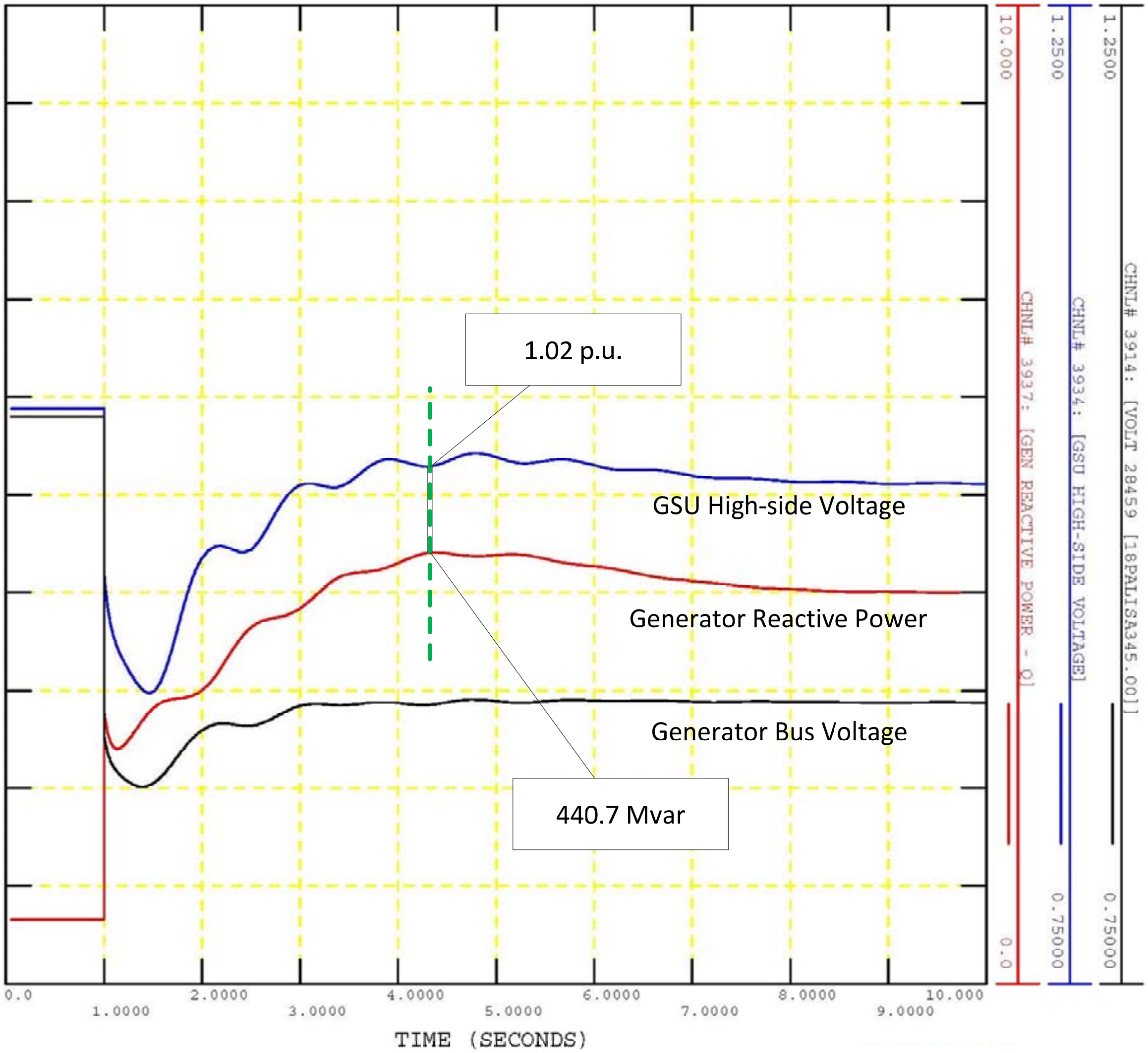
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (152) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Option 14b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle -32.2°\ MVA}$$

$$Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8^\circ\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8^\circ\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle - 52.8° \ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8° \ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle - 52.8° \ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701 \angle - 52.8° \ A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle - 52.8° \ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = \ GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \ MVA \ \times 0.85$$

$$P = 767.6 \ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \ MW$$

$$Q = 921.12 \ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85 \ p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345 \ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

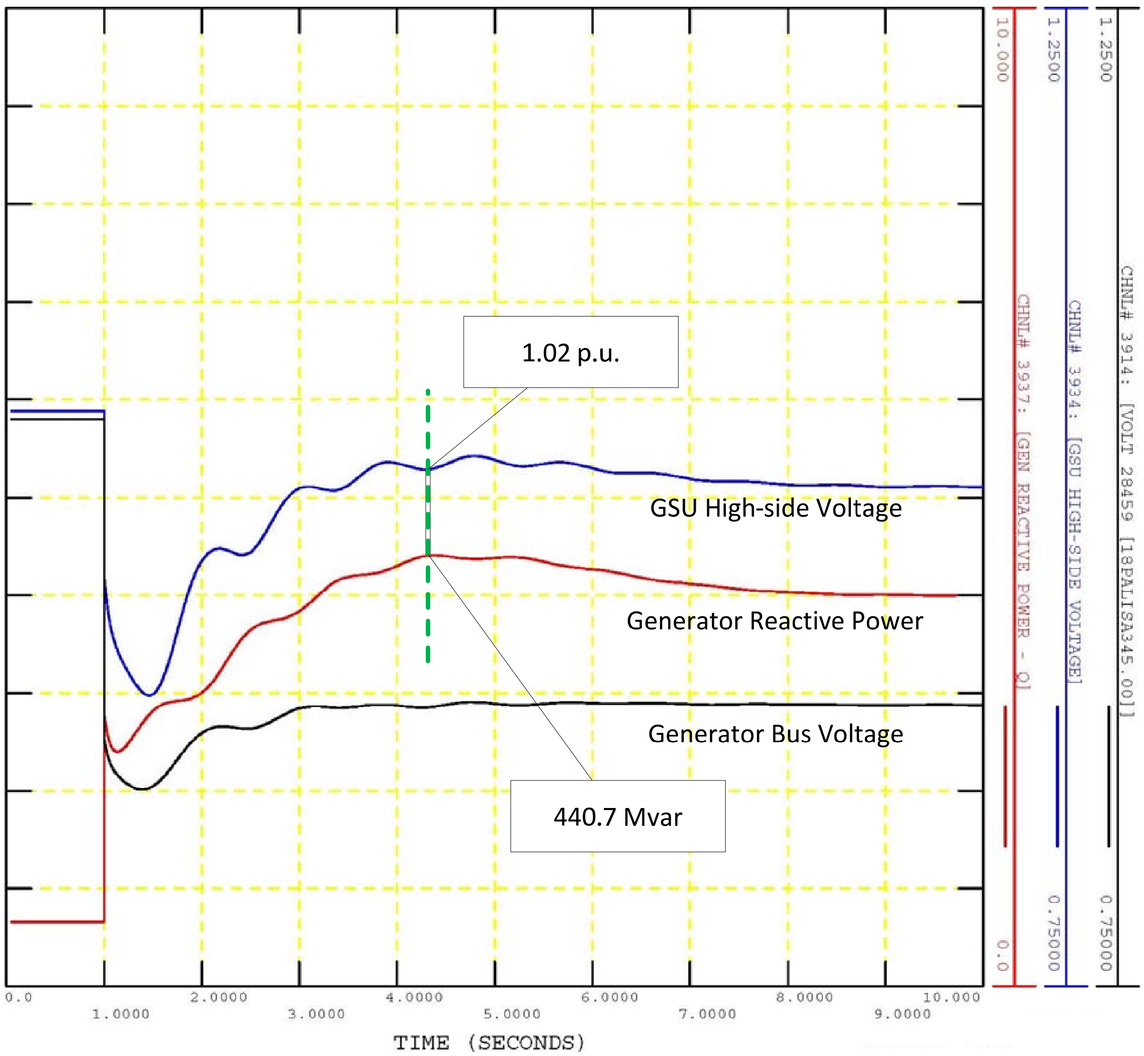
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

Example Calculations: Options 15b and 16b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 3.39\angle -32.2°\ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 3.39\angle -32.2°\ A \times 1.15$$

$$I_{\sec limit} > 3.90\angle -32.2°\ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

Eq. (175) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q):

Eq. (176) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$V_{gen} = 1.0 \times 345\ kV$

$V_{gen} = 345.0\ kV$

Apparent power (S):

Eq. (178) $S = P + jQ$

$S = 102.0\ MW + j83.2\ Mvar$

$S = 131.6\angle 39.2°\ MVA$

Primary impedance (Z_{pri}):

Eq. (179) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$Z_{pri} = 904.4\angle 39.2°\ \Omega$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $P = 3 \times GEN_{Asych\_nameplate} \times pf$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $V_{nom} = 1.0\ p.u. \times V_{nom}$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $S = P + jQ$

Example Calculations: Options 18 and 19

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017
Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period	October 30, 2017 through December 14, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays[1] at the terminals of the Elements listed in 4.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

---

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

1. **Compliance Monitoring Process**

1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring

[3] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf).

and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. **Evidence Retention:** The following evidence retention period(s) 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 Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity 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 Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, “Considerations for Power Plant and Transmission System Protection Coordination,” technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, “Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition.” (Date of Publication: March 2016)

IEEE C37.102-2006, “IEEE Guide for AC Generator Protection.” (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Project 2016-04
2	TBD	Adopted by NERC Board of Trustees	Revision
2	TBD	FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.

bility Evaluation Criteria

Relay Type	Option	Bus Voltage[5]	Setting Criteria
hase overcurrent lay (e.g., 50 or 1)	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
The same application continues on the next page with a different relay type			

[5] e high-side of the GSU transformer use Option 15

bility Evaluation Criteria			
Relay Type	Option	Bus Voltage[5]	Setting Criteria
nase directional vercurrent relay .g., 67) – rectional toward e Transmission stem	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

e high-side of the GSU transformer use, Option 16

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51)[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.
[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Setting Criteria
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

bility Evaluation Criteria			
Relay Type	Option	Bus Voltage[5]	Setting Criteria
hase stantaneous vercurrent pervisory ement (e.g., 50) – sociated with urrent-based, ommunication-sisted schemes here the scheme capable of ipping for loss of ommunications nd/or phase time vercurrent relay .g., 51)	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

The same application continues on the next page with a different relay type

he generator-side of the GSU transformer, use Option 8.

bility Evaluation Criteria			
Relay Type	**Option**	**Bus Voltage[5]**	**Setting Criteria**
hase directional stantaneous vercurrent pervisory ement (e.g., 67) – sociated with rrent-based, ommunication- sisted schemes here the scheme capable of ipping for loss of ommunications rectional toward e Transmission stem and/or hase directional me overcurrent lay (e.g., 67) – rectional toward e Transmission stem	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
	OR		
	16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

e generator-side of the GSU transformer, use Option 9

bility Evaluation Criteria			
Relay Type	Option	Bus Voltage[5]	Setting Criteria
hase distance lay (e.g., 21) – rectional toward e Transmission stem	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

The same application continues on the next page with a different relay type

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications and/or Phase time overcurrent relay (e.g., 51)	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or Phase directional time overcurrent relay (e.g., 67)	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[17] If the relay is installed on the generator-side of the GSU transformer, use Option 12.

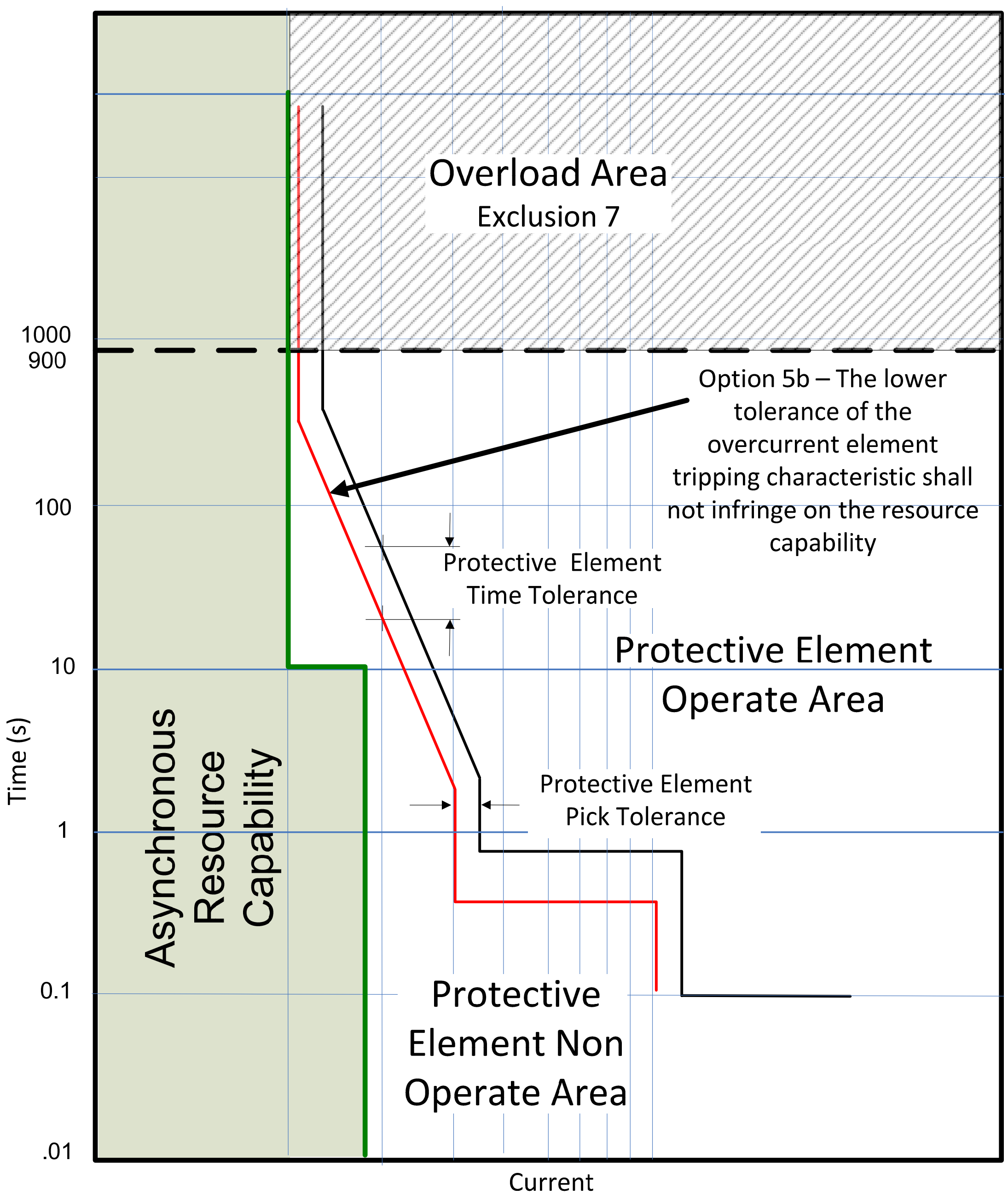


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

[18] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf.

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

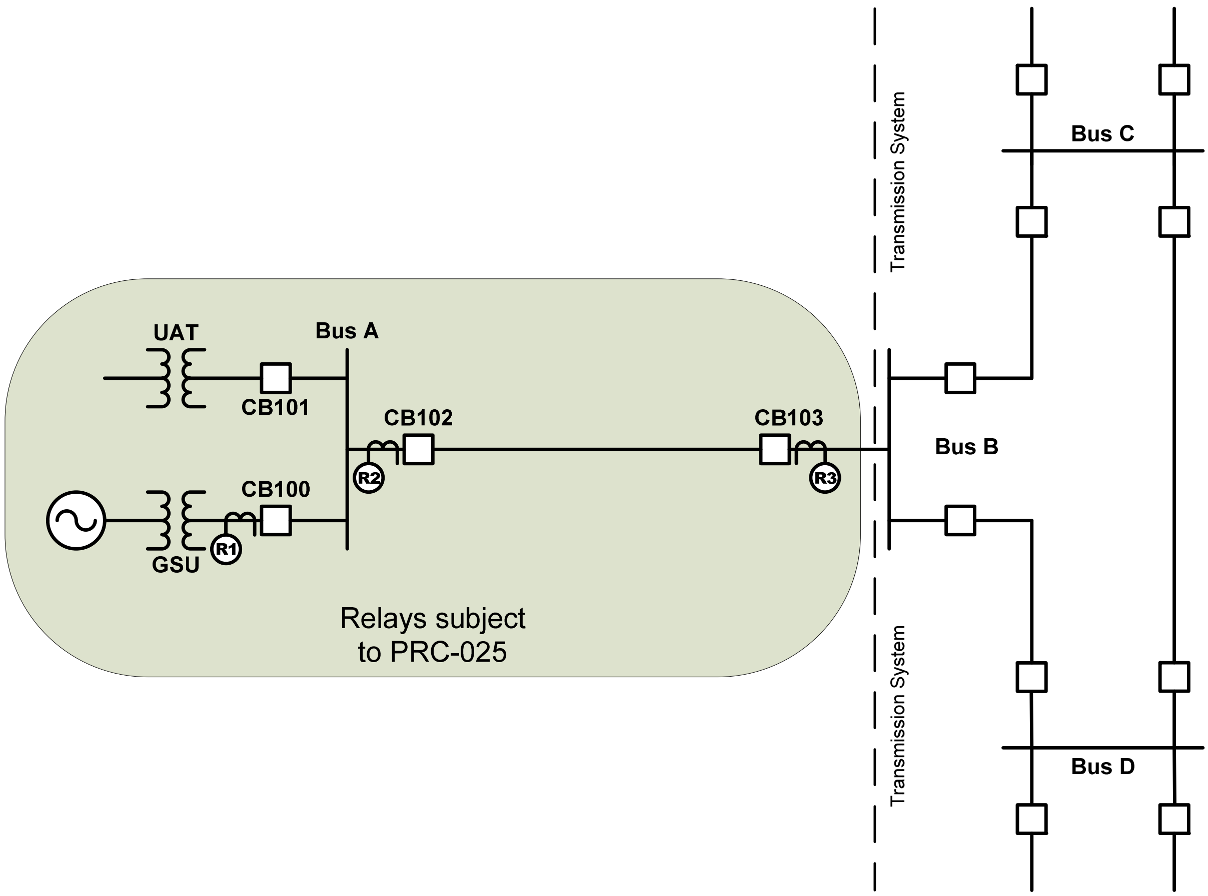


Figure 1: Generation exported through a single radial line

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

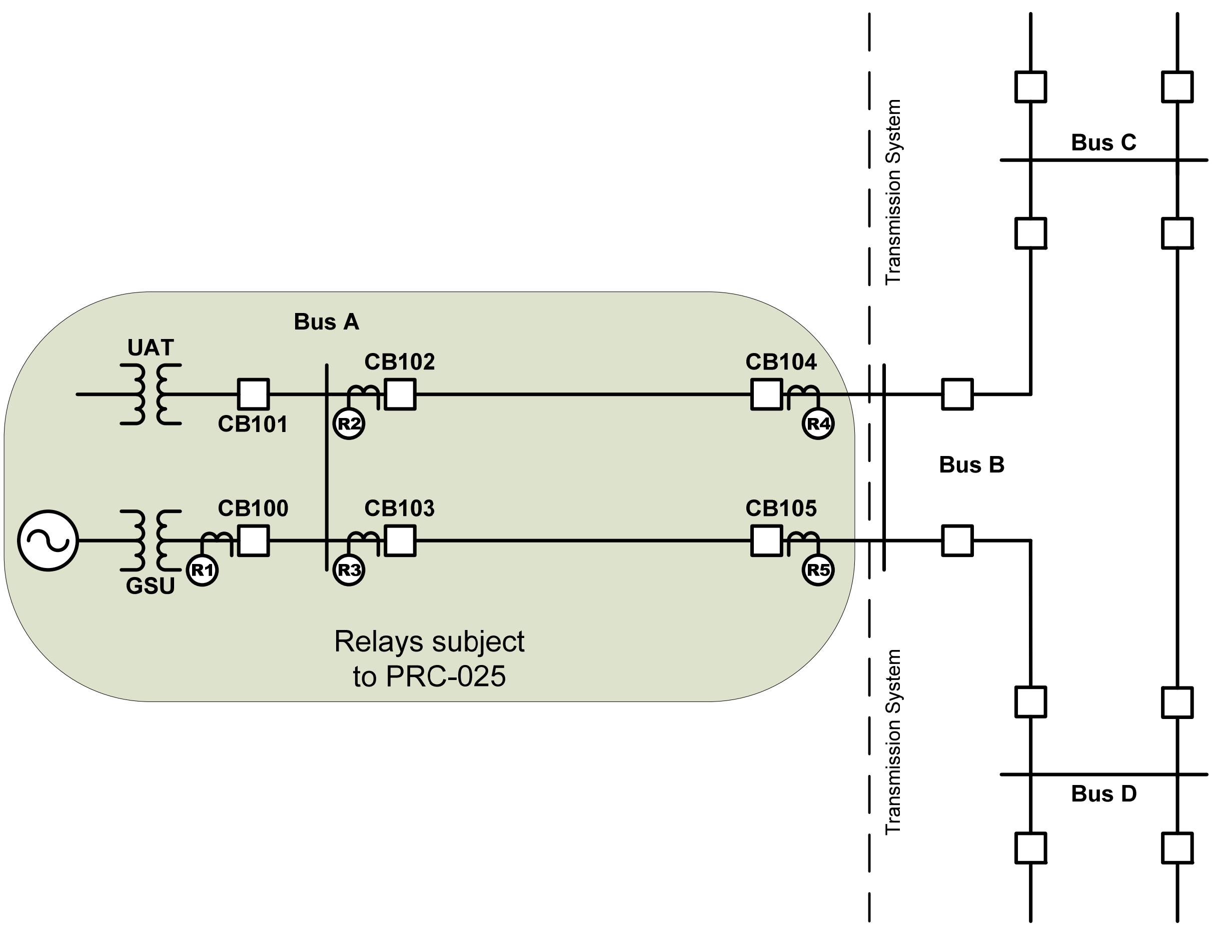


Figure 2: Generation exported through multiple radial lines

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

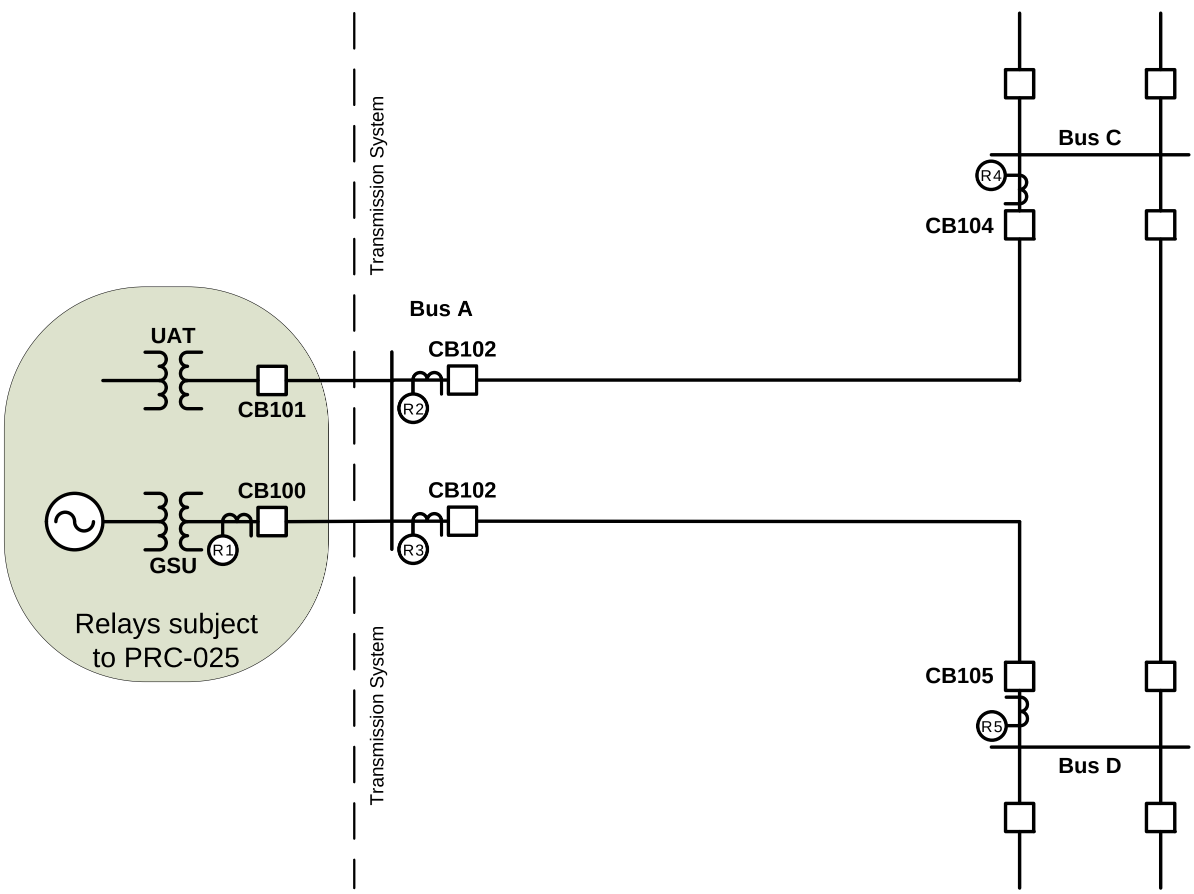


Figure 3: Generation exported through a network

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called *Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition*,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a “collector system” or “feeders”) consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

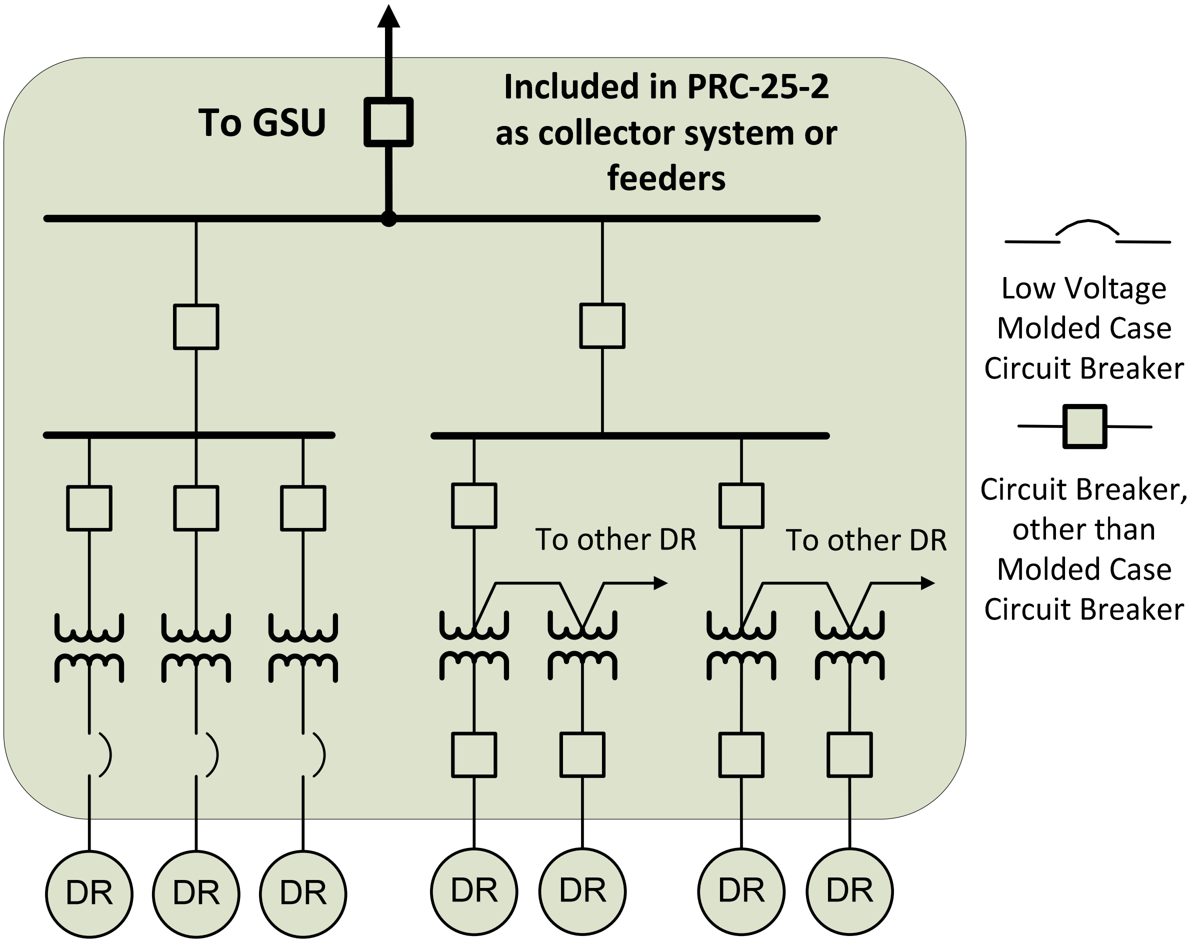


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column “Setting Criteria” are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within

the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage at the relay location to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power

achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage*

> *regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differ from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differ from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting

criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 5 and 6 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

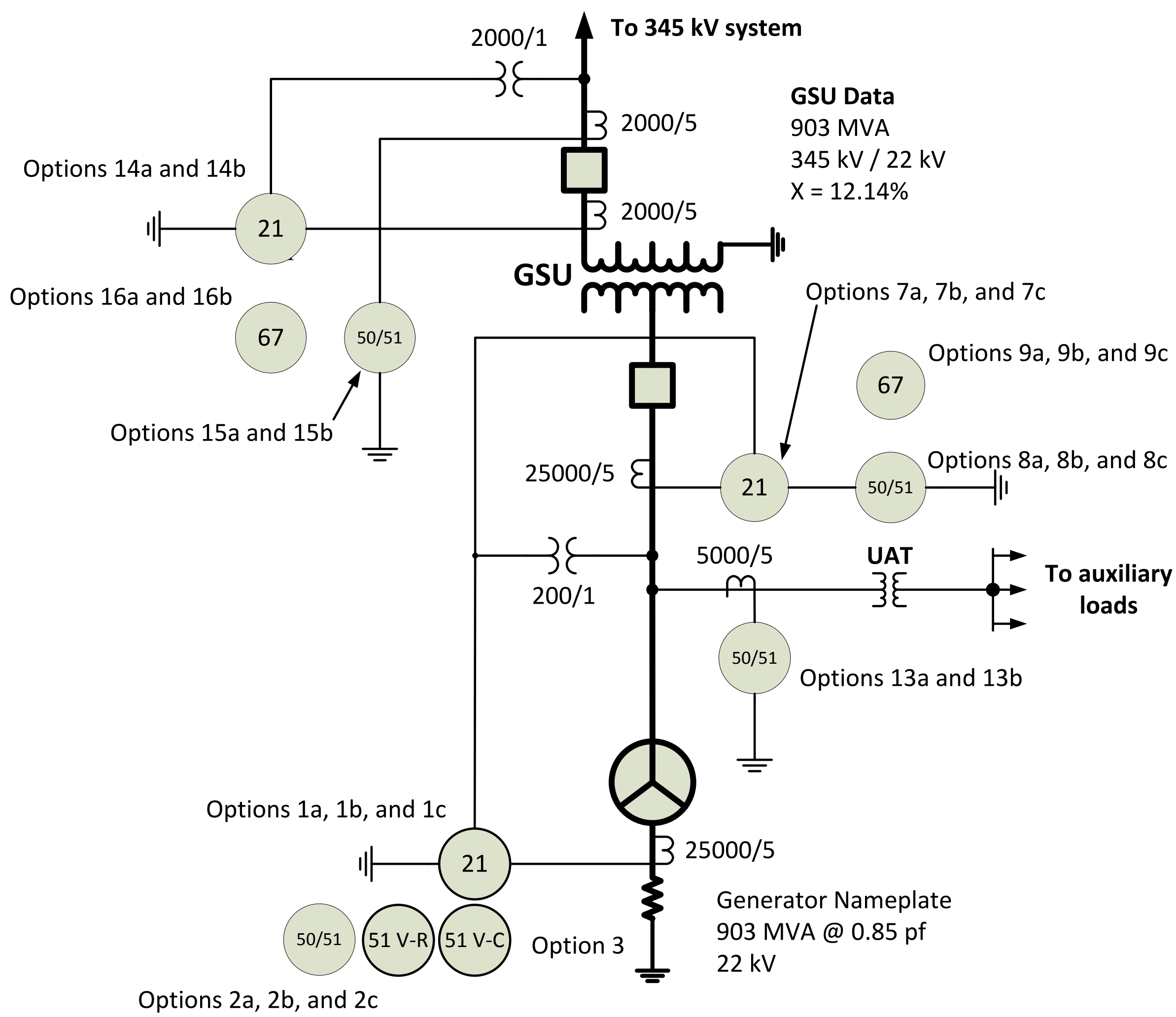


Figure 5: Relay Connection for corresponding synchronous options

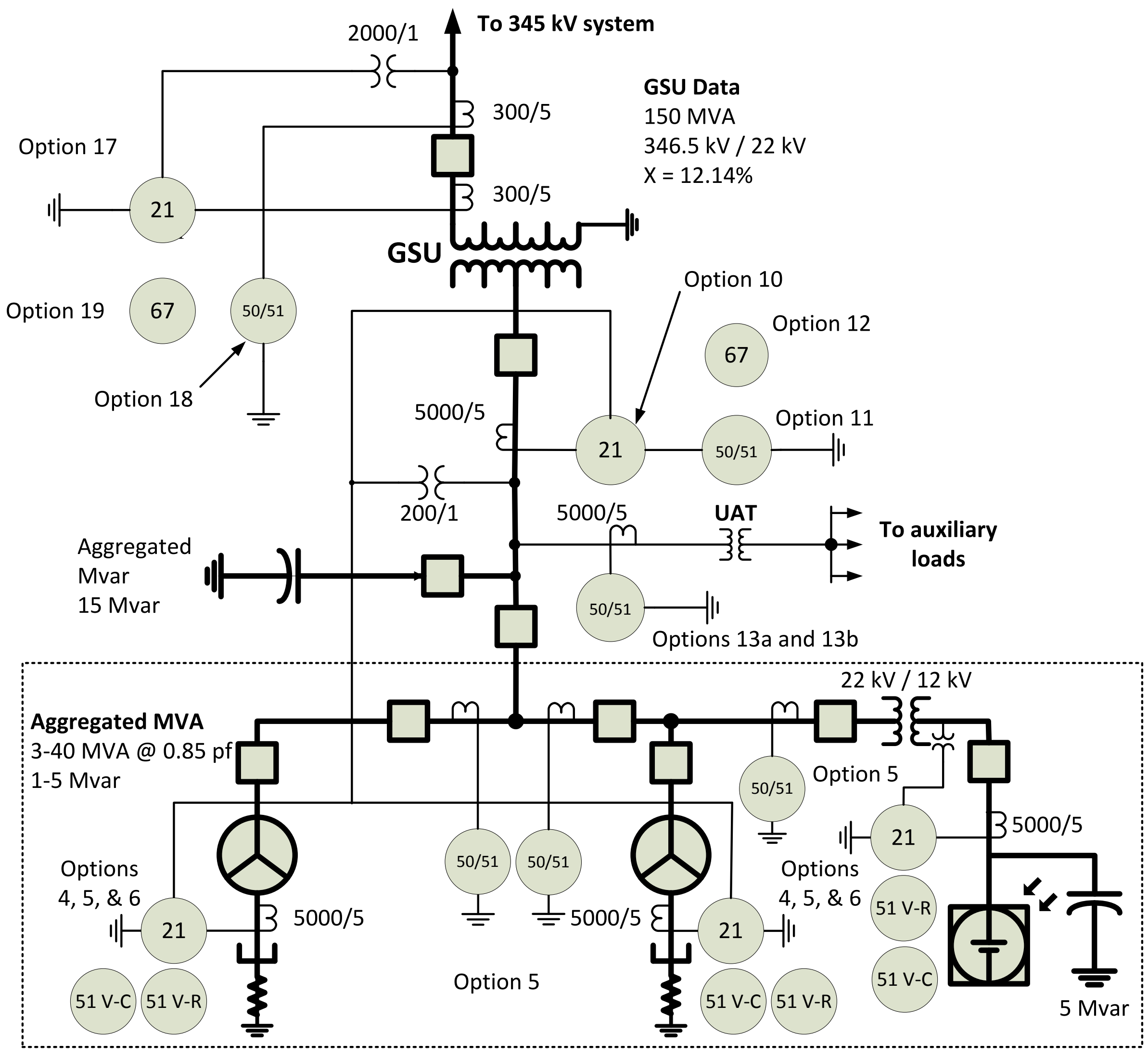


Figure 6: Relay Connection for corresponding asynchronous options including inverter-based installations

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50, 51, or 51V-R – voltage-restrained). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback.

Refer to the Figures 7 and 8 below for example configurations:

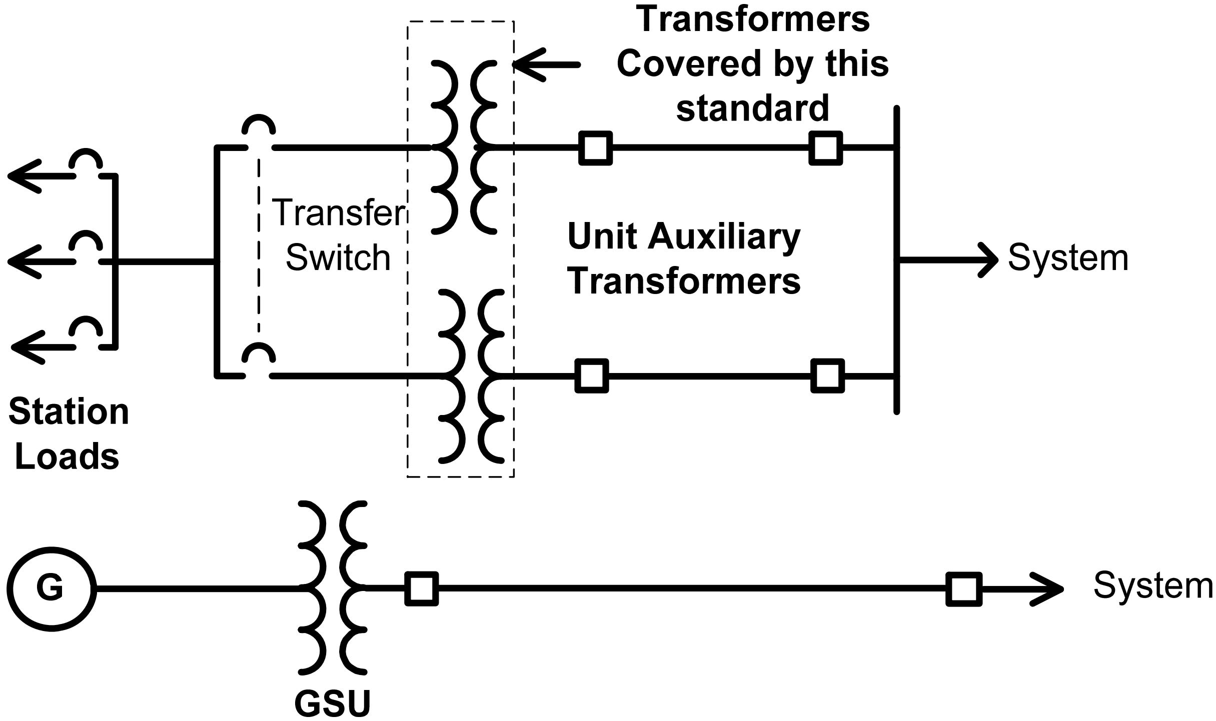


Figure 7: Auxiliary Power System (independent from generator)

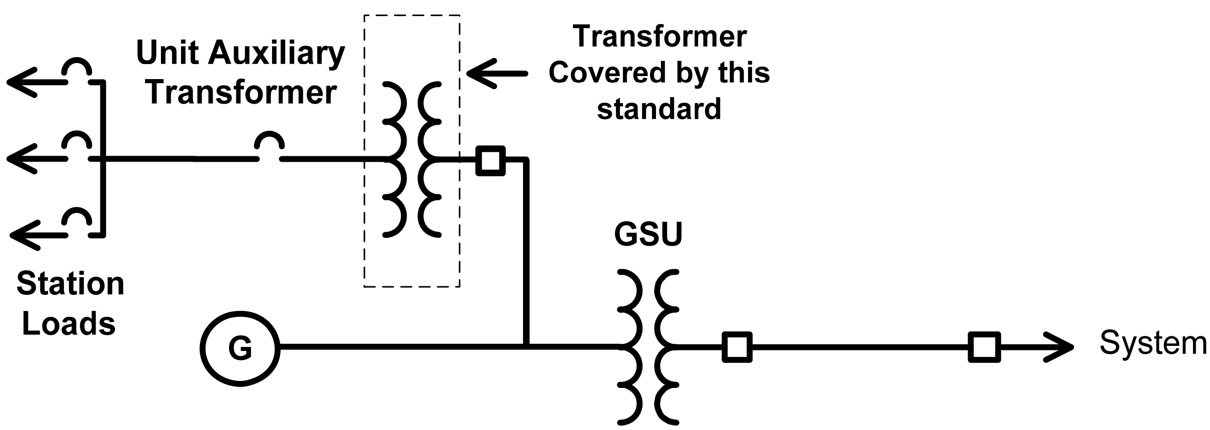


Figure 8: Typical auxiliary power system for generation units or plants

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity

for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at

the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differ from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard.

Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT ~~low~~high-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times [V_{high-side}]\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

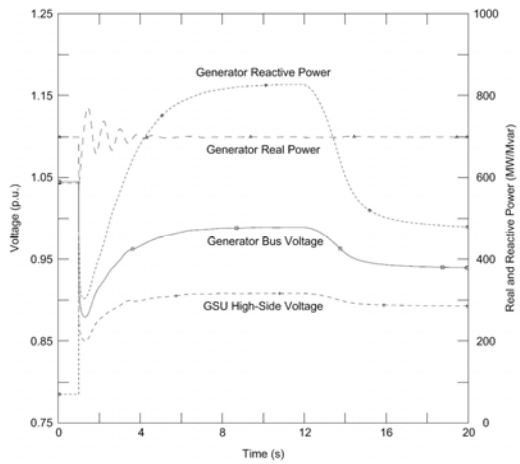
$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ k\text{V}$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 2a

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (*MVA_base*).

Real Power output (P):

Eq. (38) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Option 2b

Transformer impedance:

Eq. (40) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Option 2b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\, p.u. \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{bus} = 21.90\, kV$$

Apparent power (S):

Eq. (46) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\, MW + j1151.3\, Mvar$$

$$S = 1347.4\angle 58.7°\, MVA$$

Example Calculations: Option 2b

Primary current (I_{pri}):

Eq. (47) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $$I_{\sec limit} > I_{sec} \times 115\%$$

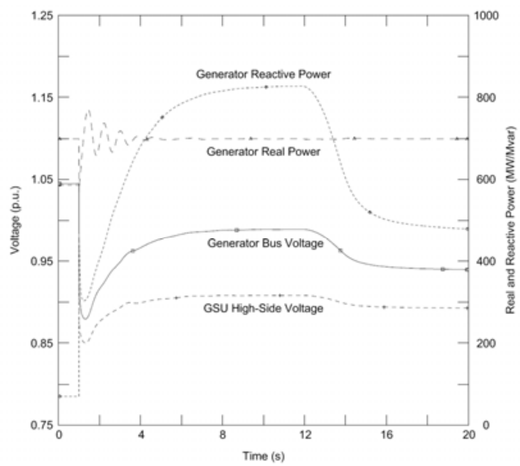
$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$

Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\sec limit} > I_{sec} \times 115\%$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = \ GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\,p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° \, A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40 \, MVA \times 0.85$$

$$P = 102.0 \, MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \, Mvar + 5 \, Mvar + (3 \times 40 \, MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \, Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0 \, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \, kV \times \left(\frac{22 \, kV}{346.5 \, kV}\right)$$

$$V_{gen} = 21.9 \, kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0 \, MW + j83.2 \, Mvar$$

$$S = 131.6\angle 39.2° \, MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $Q_{Synch} = 150\% \times P_{Synch}$

$Q_{Synch} = 1.50 \times 767.6\ MW$

$Q_{Synch} = 1151.3\ MW$

Apparent power (S_{Synch}):

Eq. (79) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q_{Asynch}):

Eq. (81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Apparent power (S_{Asynch}):

Eq. (82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32 \angle 56.8° \ \Omega}{1.00}$$

$$Z_{\sec limit} = 6.32 \angle 56.8° \ \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \ \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0° \ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent~~s~~ the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \ MVA \times 0.85$$

$$P = 767.6 \ MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8a and 9a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent~~s~~ a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU ~~T~~transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (106) $$S = P_{Synch\_reported} + jQ$$

Example Calculations: Options 8b and 9b

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Example Calculations: Options 8a, 9a, 11, and 12

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $P_{Synch} = GEN_{Synch\_nameplate} \times pf$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $Q_{Synch} = 150\% \times P_{Synch}$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $I_{pri-sync} = \dfrac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-sync} = 43061 \angle -58.7° \, A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \, MVA \times 0.85$$

$$P_{Asynch} = 102.0 \, MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \, Mvar + 5 \, Mvar + (3 \times 40 \, MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \, Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \, kV \times \left(\frac{22 \, kV}{346.5 \, kV}\right)$$

$$V_{gen} = 20.81 \, kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0 \, MW + j83.2 \, Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2° \, MVA$$

Primary current ($I_{pri-async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{pri-async} = \frac{171.1 \angle -39.2° \, MVA}{1.73 \times 20.81 \, kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514 \angle -56.8° \, A \times 1.00$$

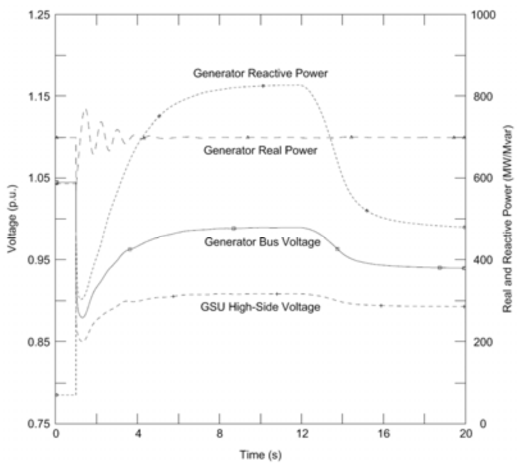
$$I_{\sec limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 8c and 9c



In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (122) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (123) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus\_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

Example Calculations: Options 8c and 9c

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option 10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Option 10

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $V_{gen} = 1.0\, p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 1.0 \times 345\, kV \times \left(\frac{22\, kV}{346.5\, kV}\right)$$

$$V_{gen} = 21.9\, kV$$

Apparent power (S):

Eq. (129) $S = P + jQ$

$$S = 102.0\, MW + j83.2\, Mvar$$

$$S = 131.6\angle 39.2°\, MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\, kV)^2}{131.6\angle -39.2°\, MVA}$$

$$Z_{pri} = 3.644\, \angle 39.2°\, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 3.644\, \angle 39.2°\, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\, \angle 39.2°\, \Omega \times 5$$

$$Z_{sec} = 18.22\, \angle 39.2°\, \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $Z_{\sec limit} = \frac{Z_{sec}}{130\%}$

Example Calculations: Option 10

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA\ \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen\_static} + (3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf)))$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\ \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51\ A \times 1.50$$

$$I_{\sec limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283\angle 85.0°\ \Omega$$

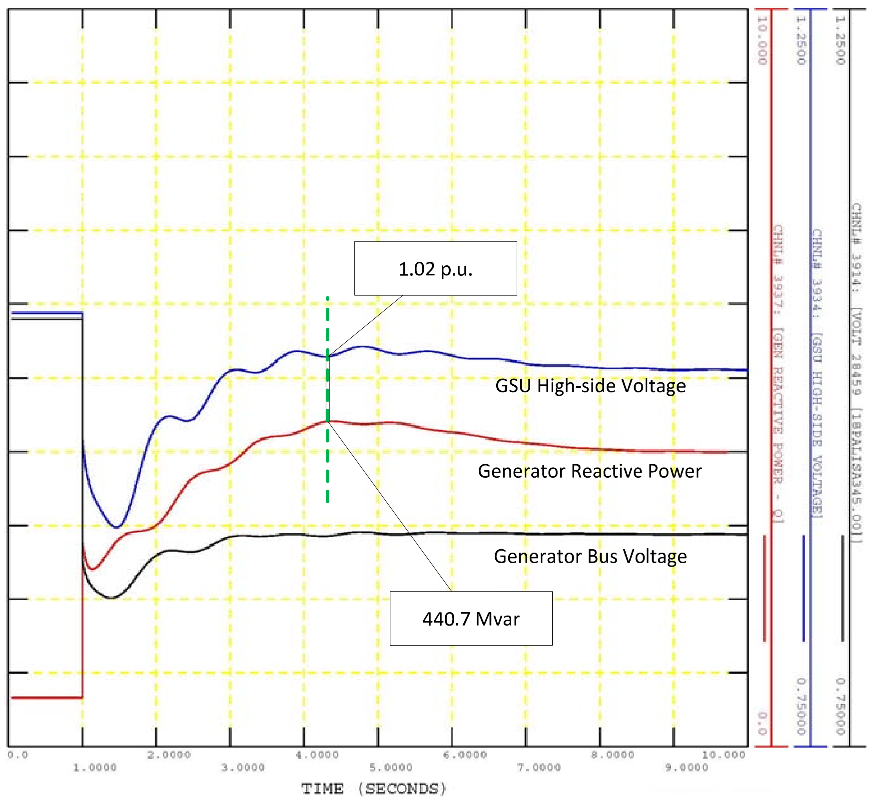
Example Calculations: Option 14b

Option 14b represents the simulation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (152) $S = P_{Synch\_reported} + jQ$

Example Calculations: Option 14b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(351.9\ kV)^2}{827.2\angle - 32.2°\ MVA}$$

$$Z_{pri} = 149.7\angle 32.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 149.7\angle 32.2°\ \Omega \times 0.2$$

$$Z_{sec} = 29.9\angle 32.2°\ \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{29.9\angle 32.2°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 26.0\angle 32.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 32.2°$$

Example Calculations: Option 14b

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{26.0\ \Omega}{\cos(85.0° - 32.2°)}$$

$$Z_{max} < \frac{26.0\ \Omega}{0.61}$$

$$Z_{max} < 43.0\angle 85.0°\ \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at ~~at~~ the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end

Example Calculations: Options 15a and 16a

of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $Q = 120\% \times P$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $V_{bus} = 0.85\ p.u. \times V_{nom}$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = 2280.6\angle -52.8° \, A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8° \, A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8° \, A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701 \angle -52.8° \, A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle -52.8° \, A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \, MW$$

$$Q = 921.12 \, Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85 \, p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345 \, kV$$

Example Calculations: Options 15a and 16a

$$V_{bus\_remote\_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle -52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation.

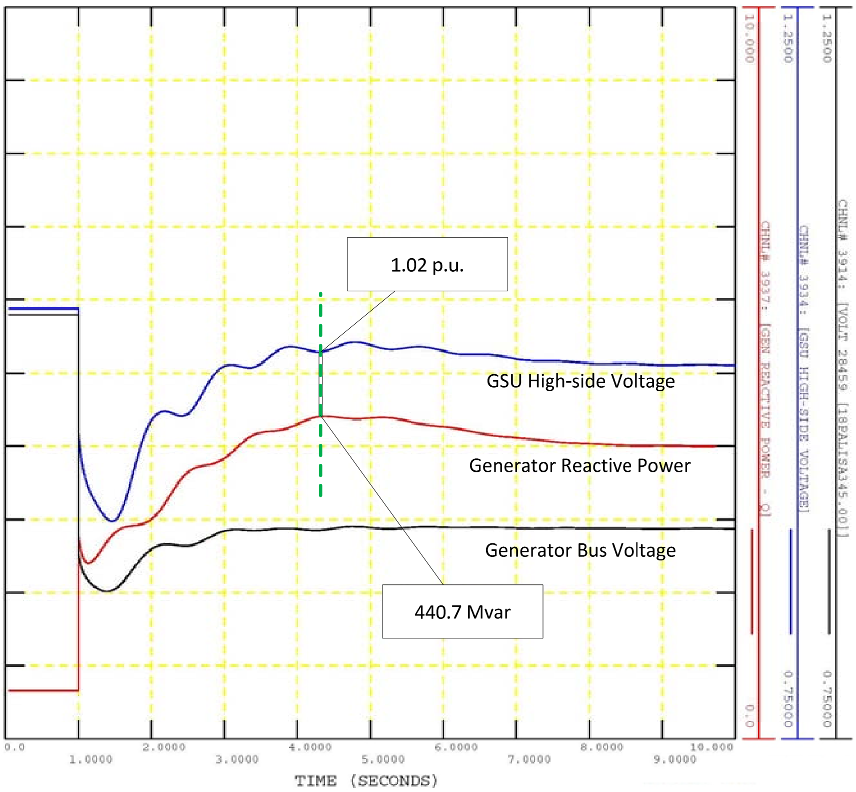
Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as these values will correspond to the lowest apparent impedance at the relay location. The corresponding simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



In this simulation the following values are derived:

$$Q = 440.7\ Mvar$$

$$V_{bus\_simulated} = 1.02 \times V_{nom} = 351.9\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Apparent power (S):

Eq. (171) $S = P_{Synch\_reported} + jQ$

Example Calculations: Options 15b and 16b

$$S = 700.0\ MW + j440.7\ Mvar$$

$$S = 827.2\angle 32.2°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{827.2\angle -32.2°\ MVA}{1.73 \times 351.9\ kV}$$

$$I_{pri} = 1357.1\angle -32.2°\ A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1357.1\angle -32.2°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 3.39\angle -32.2°\ A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 3.39\angle -32.2°\ A \times 1.15$$

$$I_{\sec limit} > 3.90\angle -32.2°\ A$$

Example Calculations: Option 17

Option 17 represents the calculation for relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Option 17

Real Power output (P):

Eq. (175) $P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$

$P_{Asynch} = 3 \times 40\ MVA\ \times 0.85$

$P_{Asynch} = 102.0\ MW$

Reactive Power output (Q):

Eq. (176) $Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$

$Q_{Asynch} = 83.2\ Mvar$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $V_{bus} = 1.0\ p.u. \times V_{nom}$

$V_{gen} = 1.0 \times 345\ kV$

$V_{gen} = 345.0\ kV$

Apparent power (S):

Eq. (178) $S = P + jQ$

$S = 102.0\ MW + j83.2\ Mvar$

$S = 131.6\angle 39.2°\ MVA$

Primary impedance (Z_{pri}):

Eq. (179) $Z_{pri} = \frac{V_{bus}^2}{S^*}$

$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$

$Z_{pri} = 904.4\angle 39.2°\ \Omega$

Example Calculations: Option 17

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2° \ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2° \ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2° \ \Omega$$

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2° \ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2° \ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{20.869 \ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869 \ \Omega}{0.697}$$

$$Z_{max} < \ 29.941\angle 85.0° \ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a

Example Calculations: Options 18 and 19

GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

Example Calculations: Options 18 and 19

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle -39.2°\ A$$

End of calculations

Rationale

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

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, "while maintaining reliable fault protection" in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC 025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017
Draft 1 of PRC-025-2 was posted for a 45-day formal comment period with an initial ballot conducted in the last 10 days of the comment period	July 25, 2017 through September 9, 2017
Draft 2 of PRC-025-2 was posted for a 45-day formal comment period with an additional ballot conducted in the last 10 days of the comment period	October 30, 2017 through December 14, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**
2. **Number:** **PRC-025-~~1~~2**
3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.
4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owner that applies load-responsive protective relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

4.1.2. Transmission Owner that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

4.1.3. Distribution Provider that applies load-responsive protective ~~relays~~relays[1] at the terminals of the Elements listed in ~~3~~4.2, Facilities.

4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

4.2.1. Generating unit(s).

4.2.2. Generator step-up (i.e., GSU) transformer(s).

4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[2]

4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~, except that Elements may also supply generating plant loads.

4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] Relays include low voltage protection devices that have adjustable settings.

[2] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[3]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. **Standard Only Definition:** None.

~~6.1. **Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

~~6.1.~~ **Compliance Enforcement Authority**

1.1. ~~As defined in the NERC Rules of Procedure,~~: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise

[3] Interim Report ~~Interim Report:~~: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf~~)~~).

designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. **Evidence Retention**: The following evidence retention ~~periods~~period(s) 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 Compliance Enforcement Authority ~~(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 ~~Generator Owner, Transmission Owner, and Distribution Provider~~applicable entity shall keep data or evidence to show compliance as identified below unless directed by its ~~CEA~~Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider 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.~~

~~**6.2. Compliance Monitoring and Assessment Processes**~~

~~Compliance Audit~~

~~Self-Certification~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaint~~

~~**6.3. Additional Compliance Information**~~

~~None~~

~~Table of Compliance Elements~~

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-Term Planning~~	~~High~~	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

Deleted Cells

Deleted Cells

D. Regional Variances

None.

~~E. Interpretations~~

~~None.~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

NERC System Protection and Control Subcommittee, "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition." (Date of Publication: March 2016)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	Standards Committee acceptance of the Standards Authorization Request	Project 2016-04
2	TBD	Adopted by NERC Board of Trustees	Revised
2	TBD	FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in ~~3~~4.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads~~.),~~), the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can

result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (except that Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[4]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.
8. Low voltage protection devices that do not have adjustable settings.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

[4] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.
The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
		2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~)~~, or ~~(~~51V-R~~)~~ – voltage-restrained)	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A.
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				
	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on generator-side~~	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor

Merged Cells

Inserted Cells

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on generator-side[6] of the Generator step-up transformer(s) connected to synchronous generators	~~of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~	**OR**		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Relays installed on generator-side[7] of the Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – ~~installed on generator-side of the GSU transformer~~	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[6] If the relay is installed on the high-side of the GSU transformer, use Option 14.
[7] If the relay is installed on the high-side of the GSU transformer use, Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
	~~If the relay is installed on the high-side of the GSU transformer use Option 15~~	8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Relays installed on generator-side[8] of the Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system ~~– installed on generator-side~~	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[8] If the relay is installed on the high-side of the GSU transformer use, Option 16.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	~~of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~	9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[9]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51)~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[10]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[9] If the relay is installed on the high-side of the GSU transformer, use Option 17.
[10] If the relay is installed on the high-side of the GSU transformer, use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
~~Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)~~	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system ~~— installed on generator-side of the GSU transformer~~ ~~If the relay is installed on the high-side of the GSU transformer use Option 19~~[11]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		

Merged Cells

[11] If the relay is installed on the high-side of the GSU transformer, use Option 19.

<table>
<tr><th colspan="5">Table 1. Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>~~Pickup~~ Setting Criteria</th></tr>
<tr><td></td><td>side terminals of the UAT, for which operation of the relay will cause the associated generator to trip~~.~~</td><td>13b</td><td>Unit auxiliary transformer bus voltage corresponding to the measured current</td><td>The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner</td></tr>
<tr><td colspan="5">~~A different application starts on the next page~~</td></tr>
<tr><td colspan="5">~~A different application starts on the next page~~</td></tr>
<tr><td rowspan="4">Relays installed on the high-side of the GSU transformer,[12] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) ~~–~~ connected to synchronous generators</td><td rowspan="3">Phase distance relay (e.g., 21) – directional toward the Transmission system~~ – installed on the high-side of the GSU transformer~~

~~If the relay is installed on the generator-side of the GSU transformer use Option 7~~</td><td>14a</td><td>0.85 per unit of the line nominal voltage at the relay location</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>14b</td><td>Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">**The same application continues on the next page with a different relay type**</td></tr>
</table>

[12] If the relay is installed on the generator-side of the GSU transformer, use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[13] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~ ~~–~~) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or phase time overcurrent relay (e.g., 51)~~—~~ ~~installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

[13] If the relay is installed on the generator-side of the GSU transformer, use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			
Relays installed on the high-side of the GSU transformer,[14] including relays installed at the remote end of the line, for Elements that connect the GSU transformer(s) to the	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based,	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

[14] If the relay is installed on the generator-side of the GSU transformer, use Option 9.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant load~~.~~.) –connected to synchronous generators	communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~	16b	Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
A different application starts on the next page				
Relays installed on the high-side of the GSU transformer,[15] including relays installed on the remote end of line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply	Phase distance relay (e.g., 21) – directional toward the Transmission system ~~– installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 10~~	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

[15] If the relay is installed on the generator-side of the GSU transformer, use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	~~Pickup~~ **Setting Criteria**
generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	**The same application continues on the next page with a different relay type**			

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	~~Pickup~~ Setting Criteria
Relays installed on the high-side of the GSU transformer,[16] including, relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~installed on the high-side of the GSU transformer~~ and/or Phase time overcurrent relay (e.g., 51)~~— installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 11~~	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[16] If the relay is installed on the generator-side of the GSU transformer, use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**~~Pickup~~ Setting Criteria**
Relays installed on the high-side of the GSU transformer,[17] including relays installed on the remote end of the line, for Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (except that Elements may also supply generating plant loads~~.~~) –connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system ~~installed on the high-side of the GSU transformer~~ and/or Phase directional time overcurrent relay (e.g., 67)~~—installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 12~~	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

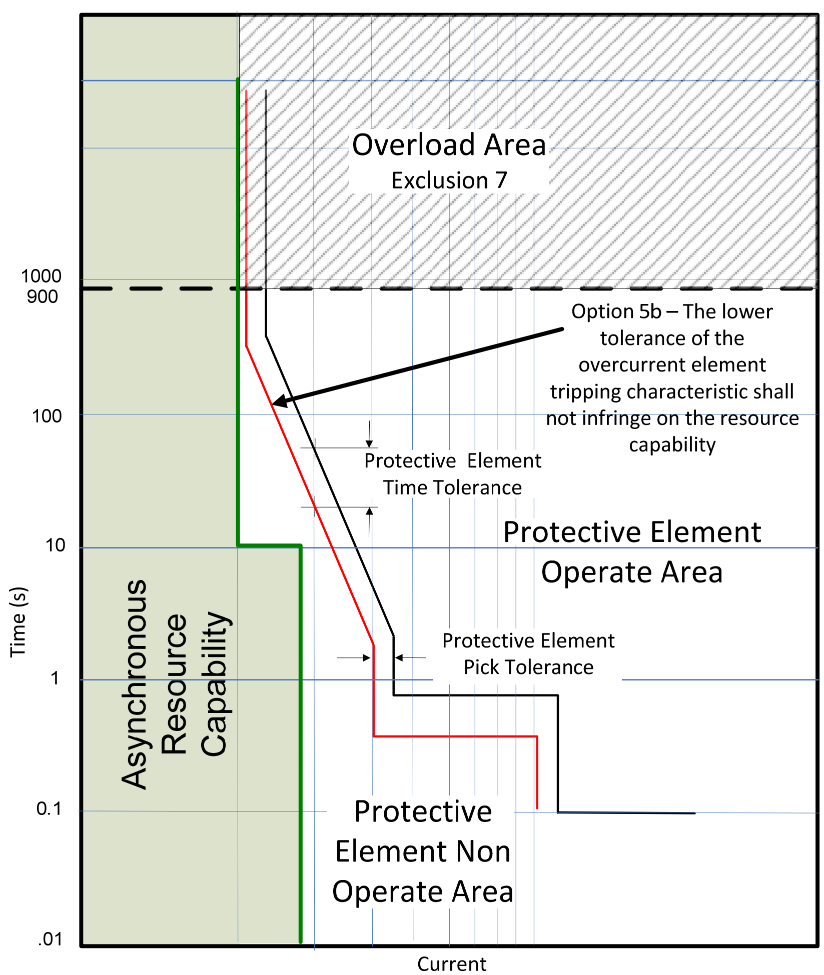


Figure A

This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination~~"Power Plant and Transmission System Protection Coordination,"~~," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[18]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed

[18] http://www.nerc.com/~~docs/pc/spctf/~~comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20
Gen%20Prot%~~20Coord%20Rev1%20Final%2007-30-2010~~20Coordination%20Technical%20Reference%20Document.pdf.

within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.

For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance ~~is~~are dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator

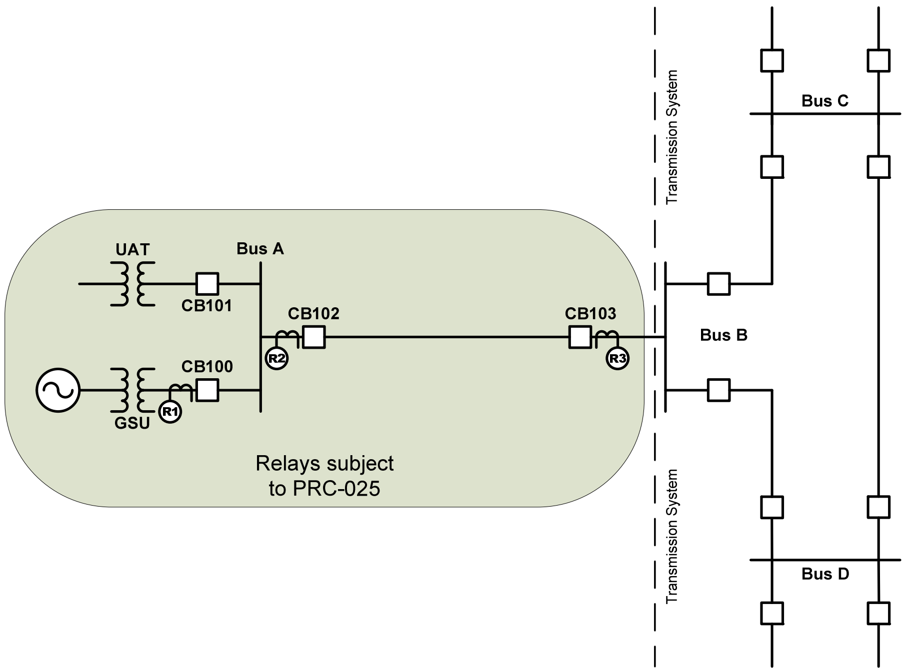
interface connections with the Transmission system, and Figure 4 illustrates examples of Elements utilized in the aggregation of dispersed power resources that are in scope of the standard.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.
~~In this particular case,~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable ~~responsible entity's~~ to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional ~~relay R3 located on breaker CB103 at Bus B looking~~ toward ~~Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not~~the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in ~~this~~the standard~~ or~~. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased ~~transmission system loading~~generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in ~~PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1~~ this standard.~~ PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


UAT
Bus A
CB101
CB102
CB103
CB100
R1
R2
R3
GSU
Bus B
Bus C
Bus D
Transmission System
Transmission System
Relays subject to PRC-025

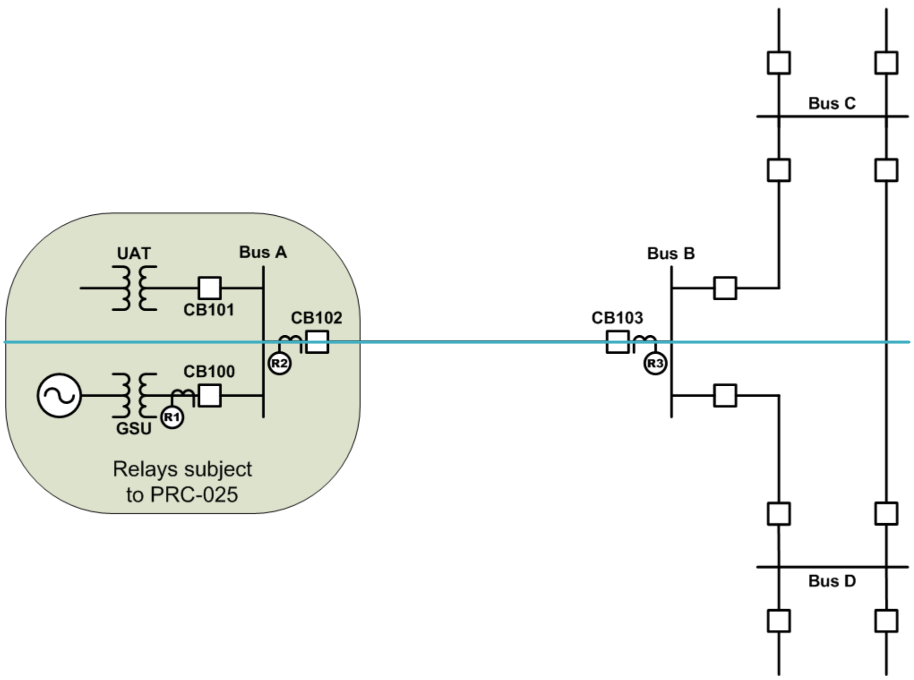


Figure 1~~.~~: Generation exported through a single radial line~~.~~

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

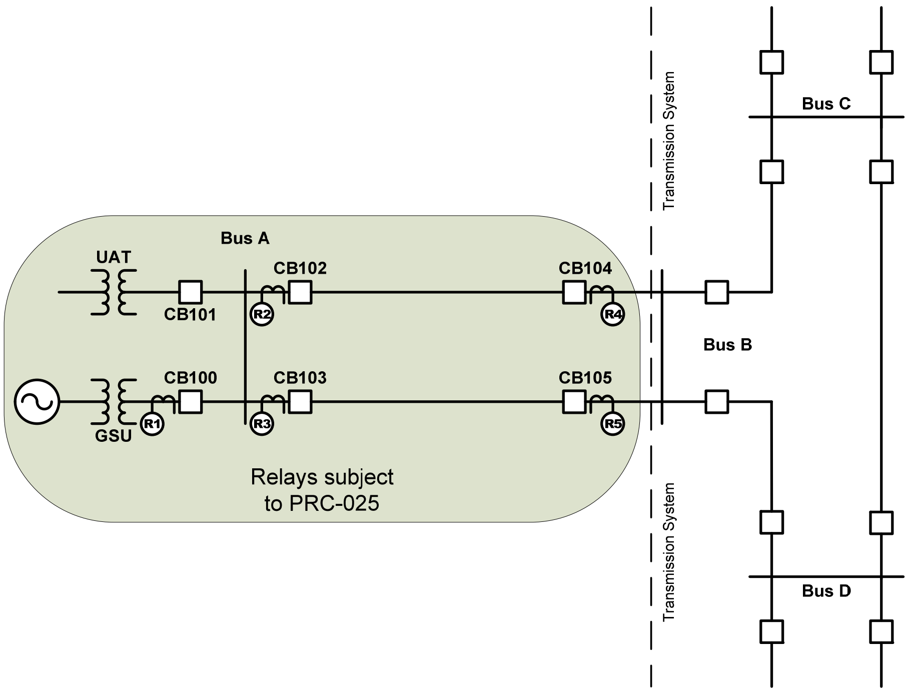


Figure 2~~.~~: Generation exported through multiple radial lines~~.~~

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

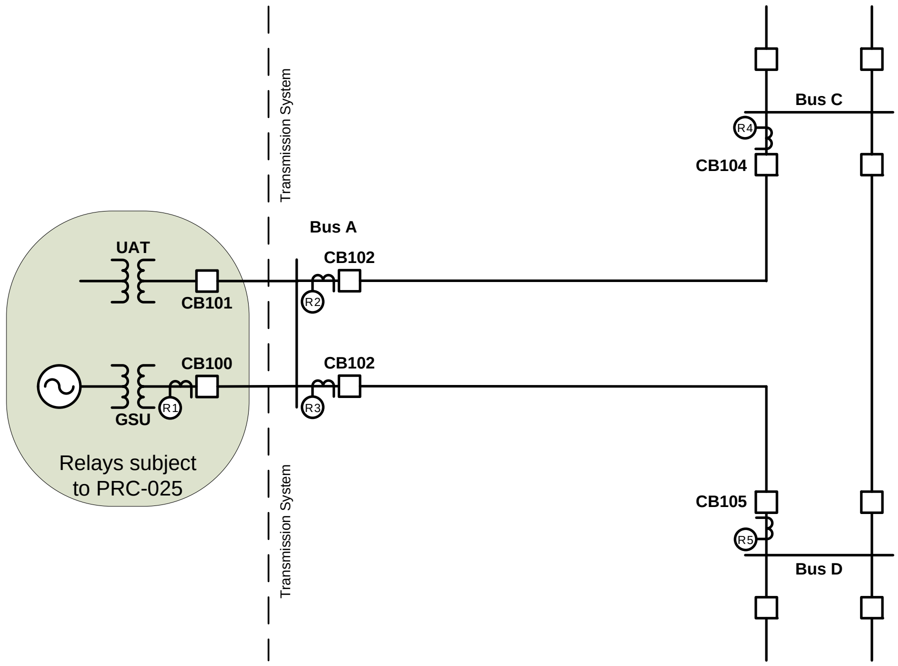


Figure 3~~.~~: Generation exported through a network~~.~~

~~Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.~~

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called

Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition,[19] March 2016.

Figure 4

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system" or "feeders") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

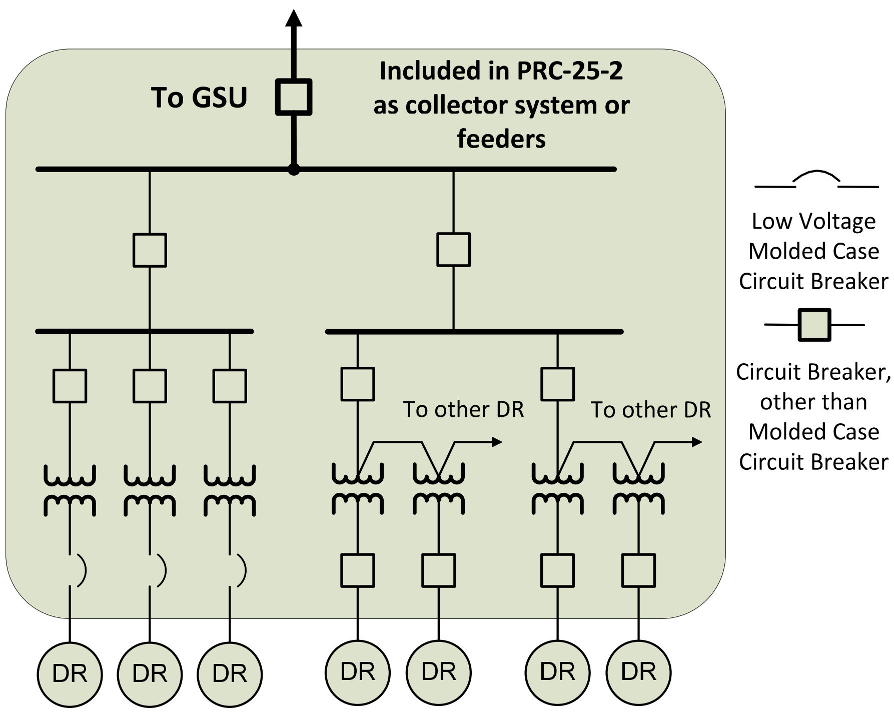


Figure-4: Elements utilized in the aggregation of dispersed power producing resources (DR)

[19] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator

Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure ~~5~~6) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage ~~to be used~~at the relay location to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault **that is not cleared by the transmission line breakers.** In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored*

> *at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options differ from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options differ from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures ~~4~~5 and ~~5~~6 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

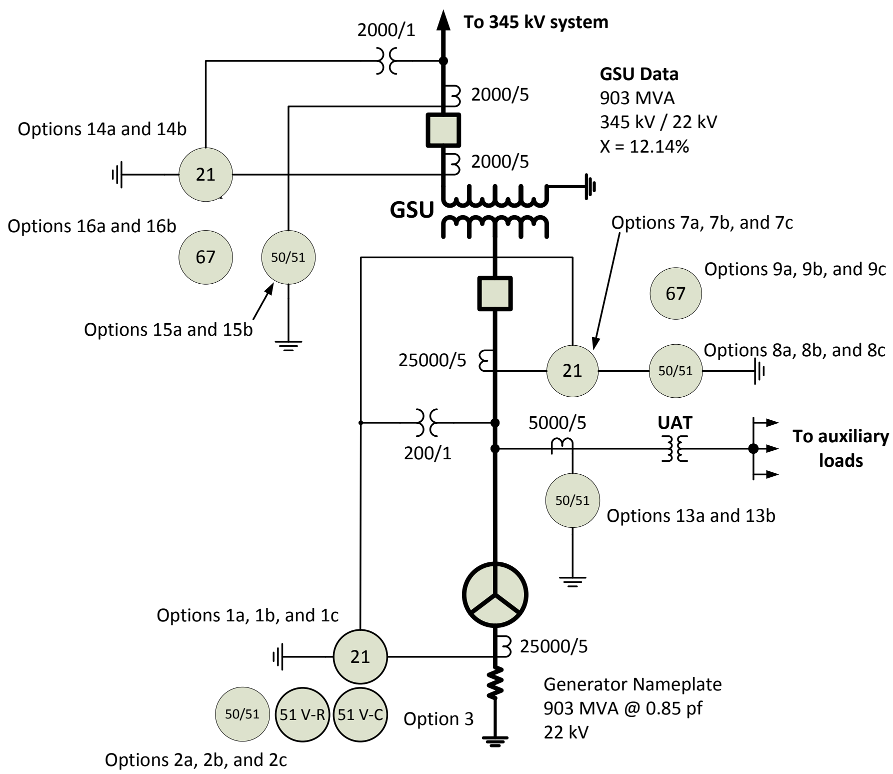


Figure ~~4.~~5: Relay Connection for corresponding synchronous options~~.~~

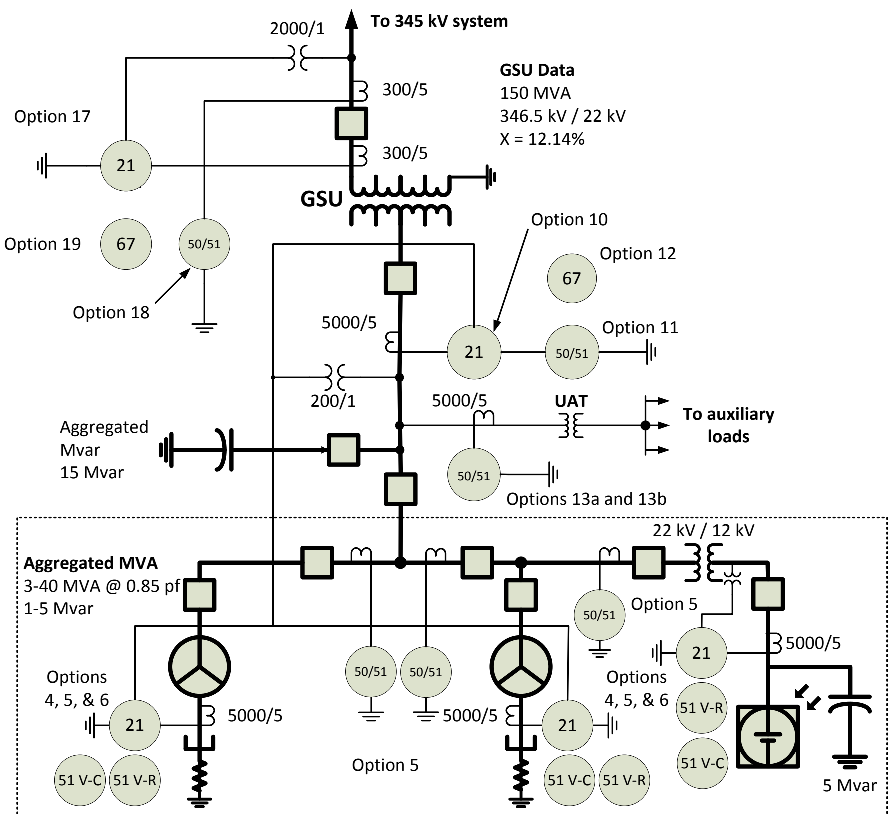


Figure ~~5.~~6: Relay Connection for corresponding asynchronous options including inverter-based installations~~.~~

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times,~~ by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~ in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage ~~-~~Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~("voltage~~-restrained~~").~~). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage (“voltage-controlled”). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage ~~-~~Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b))

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays ~~which change their sensitivity as a function of~~(e.g., 50, 51, or 51V-R – voltage ~~(“voltage~~-restrained~~”)~~). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The lower tolerance of the overcurrent element tripping characteristic shall be set to not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices). Figure A of PRC-025-2 illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying~~of phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~overcurrent~~impedance element ~~overall~~than Options 7a or 7b.

For Options 7a and 7b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 7c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on synchronous generators~~ that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 8c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer of an asynchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay

Loadability During a Transmission Depressed Voltage Condition, March 2016." These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. ~~Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.~~

Refer to the Figures ~~6~~7 and ~~7~~8 below for example configurations:

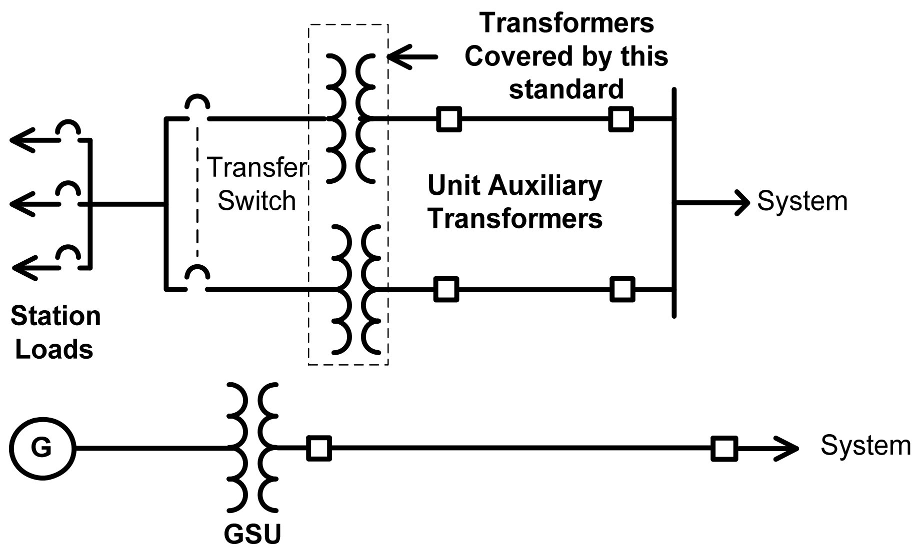


Figure ~~6~~ 7: Auxiliary Power System (independent from generator~~).~~)

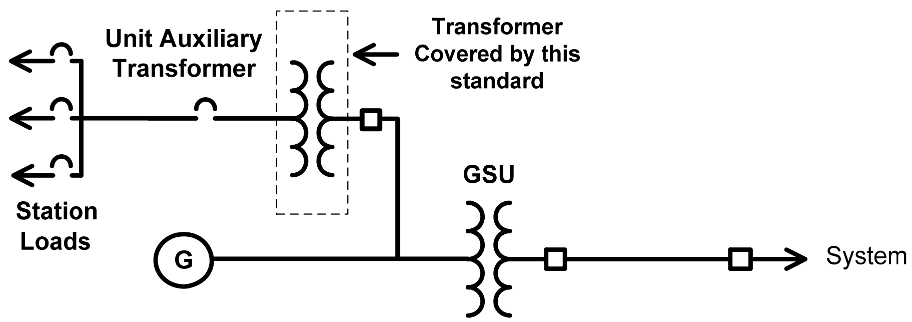


Figure ~~7~~ 8: Typical auxiliary power system for generation units or plants~~.~~

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the ~~entity's~~ relay setting philosophy of the applicable entity. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 14b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 15b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays ~~connected on the~~applied at the remote end of the line for Elements that connect a GSU transformer to the

Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Option 16b uses the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays ~~applied on~~installed on the high-side of the GSU transformer, including relays installed on the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options differ from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch\_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio\_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT ~~low~~high-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio\_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations	
Reactive Power output of static reactive device generation:	$MVAR_{gen\_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch\_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio\_remote\_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.035\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 6.9873\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~ 85° then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873\ \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873\ \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0°\ \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $P = GEN_{Synch\_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $Q_{pu} = \frac{Q}{MVA_{base}}$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

~~Eq. (15)~~ $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{\text{low-side}}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

~~Eq. (17)~~ $$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times}}{2}$$

Deleted Cells

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~ 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

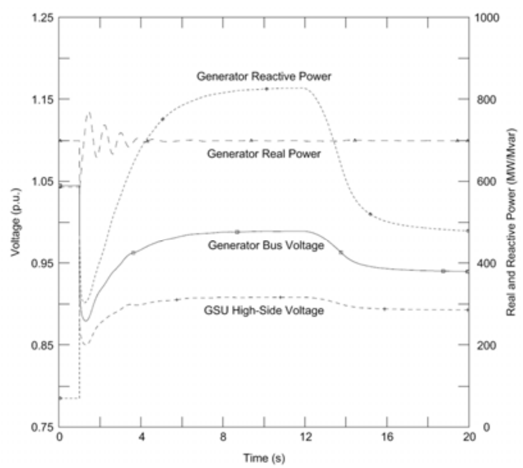
$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633\angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.



~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

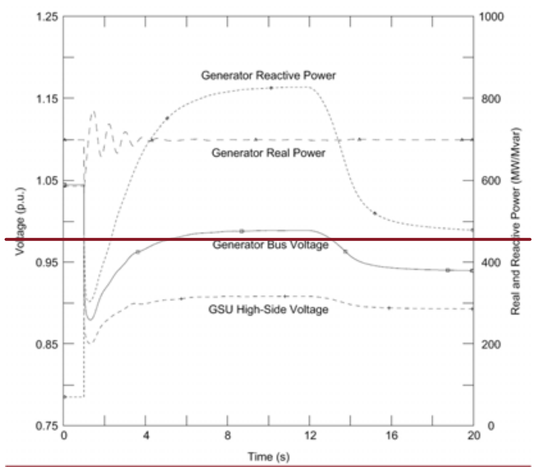
$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

Example Calculations: Options 1c and 7c

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (24) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus\_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Example Calculations: Options 1c and 7c

Secondary impedance (Z_{sec}):

$$\text{Eq. (26)} \quad Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8°\ \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

$$\text{Eq. (27)} \quad Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{10.92\angle 49.8°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 9.50\angle 49.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

$$\text{Eq. (28)} \quad Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50\ \Omega}{\cos(85.0˚ - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < 11.63\angle 85.0°\ \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R – voltage restrained) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (30) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

Example Calculations: Option 2a

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R – voltage restrained) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (*MVA*MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~ Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low-side}$ value of 0.9991 per unit for the second iteration:

Eq. (43)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

Example Calculations: Option 2b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$

$$V_{bus} = 0.9998\, p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (46) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\sec limit} > I_{sec} \times 115\%$

Example Calculations: Option 2b

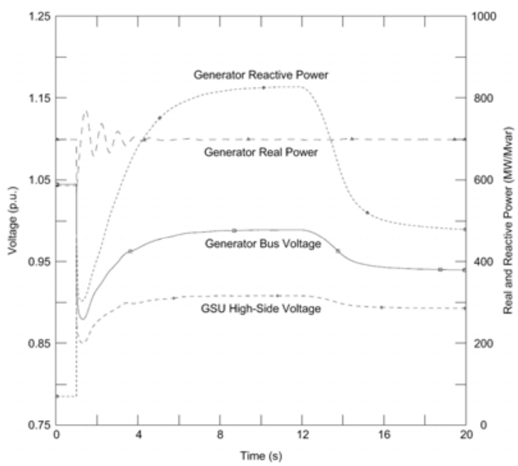
$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase time overcurrent (51V-R) voltage restrained relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.



Example Calculations: Option 2c

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.~~

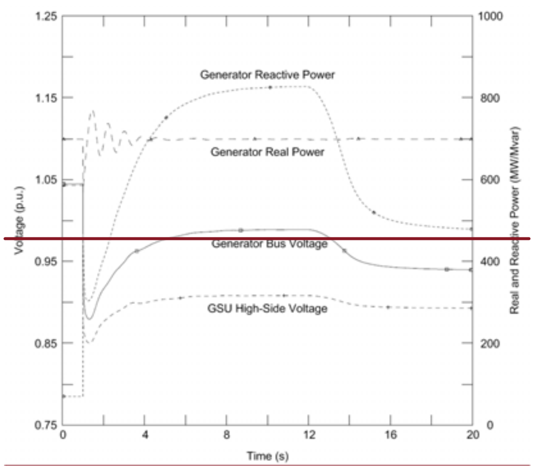
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus\_simulated} = 0.989 \times V_{gen\_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch\_reported} = 700.0\ MW$$



Apparent power (S):

Eq. (50) $S = P_{Synch\_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Example Calculations: Option 2c

Primary current (I_{pri}):

Eq. (51) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (52) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) ~~– voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

Example Calculations: Options 3 and 6

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = \ GEN_{Asych\_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Example Calculations: Option 4

Apparent power (S):

Eq. (59) $S = P + jQ$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0\angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0\angle - 31.8°\ MVA}$$

$$Z_{pri} = 11.99\ \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99\ \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95\ \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $Z_{\sec limit} = \frac{Z_{sec}}{130\%}$

$$Z_{\sec limit} = \frac{59.95\angle 31.8°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8°\ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Example Calculations: Option 4

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12\ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12\ \Omega}{0.599}$$

$$Z_{max} < 77.0\angle 85.0°\ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~– voltage-restrained~~ relay. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Example Calculations: Option 5a

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.52\angle -39.2°\ A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

~~Example Calculations: Option 5b~~

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the lower tolerance of the overcurrent element tripping characteristic shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) See Figure A for more details.

Example Calculations: Options 7a and 10

~~This~~ These examples represents~~s~~ the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

~~Real Power output (P_{sync}):~~

Real Power output (P_{sync}):

Eq. (~~71~~77) $$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (~~72~~78)
$$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (~~73~~79)
$$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80)
$$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (~~76~~82)
$$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $$S = 115\% \times \left(P_{Synch\_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8\ \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

Example Calculations: Options 7a and 10

$$Z_{sec} = 6.32\angle 56.8°\,\Omega$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~ 84 to satisfy the margin requirements in Options 7a and 10:

Eq. (~~81~~87) $$Z_{\sec limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\sec limit} = \frac{6.32\,\angle 56.8°\,\Omega}{1.00}$$

$$Z_{\sec limit} = 6.32\,\angle 56.8°\,\Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32\,\Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\,\Omega}{0.881}$$

$$Z_{max} < 7.17\angle 85.0°\,\Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represent~~s~~ the simplest calculation for synchronous generators applying a phase time overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $$P = GEN_{Synch\_nameplate} \times pf$$

Example Calculations: Options 8a and 9a

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~84~~90) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (~~86~~92) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~87~~93) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Example Calculations: Options 8a and 9a

Secondary current (I_{sec}):

Eq. (~~88~~94)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.477\ A \times 1.15$$

$$I_{\sec limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represent~~s~~ a more ~~complex~~ precise calculation for synchronous generators applying a phase time overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch\_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~90~~96)
$$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~91~~97)
$$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Example Calculations: Options 8b and 9b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU transformer *MVA*MVA_{base}).

Real Power output (P):

$$P_{pu} = \frac{P_{Synch\_reported}}{MVA_{base}} \qquad \text{Eq. } (\cancel{92}98)$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

$$Q_{pu} = \frac{Q}{MVA_{base}} \qquad \text{Eq. } (\cancel{93}99)$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

$$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}} \qquad \text{Eq. } (\cancel{94}100)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). ~~Estimate~~ Assume initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times |V_{high-side}|\right)}\right] \qquad \text{Eq. } (\cancel{95}101)$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Example Calculations: Options 8b and 9b

Eq. (~~96~~102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\, p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)

$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (~~98~~104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\, p.u.$$

Example Calculations: Options 8b and 9b

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Secondary current (I_{sec}):

Eq. (~~102~~108) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

Example Calculations: Options 8b and 9b

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 7.111\ A \times 1.15$$

$$I_{\sec limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represent~~s~~ the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110)
$$P_{Synch} = GEN_{Synch\_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111)
$$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Example Calculations: Options 8a, 9a, 11, and 12

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch\_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114) $$I_{pri-sync} = \frac{115\% \times S^*_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4\ \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061\ \angle -58.7°\ A$$

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115) $$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (~~112~~118)
$$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1\ \angle 39.2°\ MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119)
$$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2°\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri-async} = 4755 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~114~~120)
$$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

Example Calculations: Options 8a, 9a, 11, and 12

$$I_{sec} = \frac{43061 \angle -58.7°\, A}{\frac{25000}{5}} + \frac{4755\angle -39.2°\, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514\angle -56.8°\, A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~ 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98~~118:

Eq. (~~115~~121) $$I_{\sec limit} > I_{sec} \times 100\%$$

$$I_{\sec limit} > 9.514\angle -56.8°\, A \times 1.00$$

$$I_{\sec limit} > 9.514\angle -56.8°\, A$$

Example Calculations: Options 8c and 9c

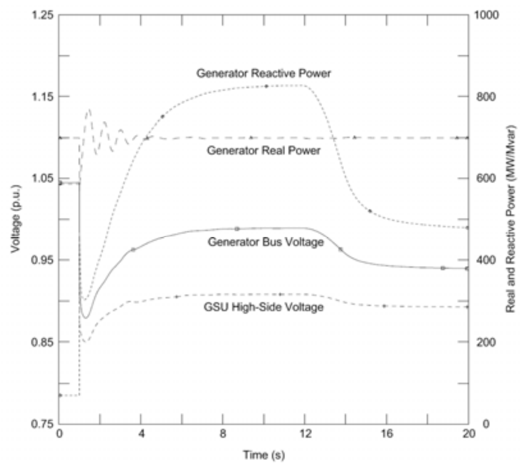
This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~ overcurrent relay~~.~~ (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used ~~as~~since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Formatted Table

Example Calculations: Options 8c and 9c

Formatted Table



In this simulation the following values are derived:

Formatted Table

$$Q = 827.4\ Mvar$$

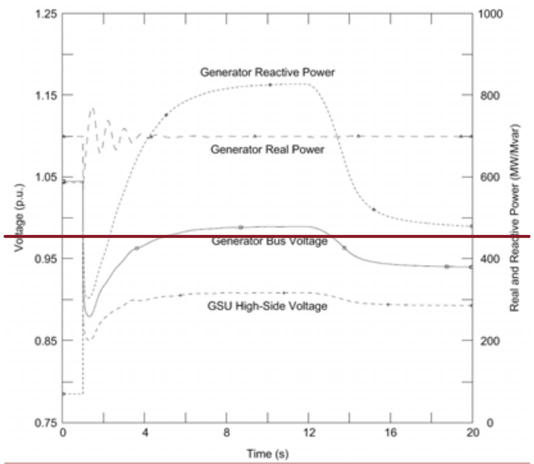
$$V_{bus\_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 8c and 9c

Formatted Table



Apparent power (S):

Eq. (~~116~~122) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (~~117~~123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (~~118~~124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8c and 9c
$I_{sec} = 5.758\ A$
To satisfy the 115% margin in Options 8c and 9c:

Eq. (~~119~~125) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.758\ A \times 1.15$$

$$I_{\sec limit} > 6.622\ A$$

Example Calculations: Option10
This examples represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) – directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~120~~126) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~121~~127) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~122~~128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

Formatted Table

Example Calculations: Option10

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~123~~129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~124~~130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~125~~131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (~~126~~132) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 14.02\angle 39.2°\ \Omega$$

Example Calculations: Option10

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~127~~133) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0°\ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~ overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~128~~134) $$P = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~129~~135) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Example Calculations: Options 11 and 12

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~130~~136)
$$V_{gen} = 1.0\, p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~131~~137)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\ \angle 39.2^\circ\ MVA$$

Primary current (I_{pri}):

Eq. (~~132~~138)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2^\circ\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2^\circ\ A$$

Secondary current (I_{sec}):

Eq. (~~133~~139)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2^\circ\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2^\circ\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (~~134~~140)
$$I_{\sec limit} > I_{sec} \times 130\%$$

Example Calculations: Options 11 and 12

$$I_{\sec limit} > 3.473\angle - 39.2° \; A \times 1.30$$

$$I_{\sec limit} > 4.515\angle - 39.2° \; A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (~~135~~141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \; MVA}{1.73 \times 13.8 \; kV}$$

$$I_{pri} = 2510.2 \; A$$

Secondary current (I_{sec}):

Eq. (~~136~~142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \; A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (~~137~~143) $$I_{\sec limit} > I_{sec} \times 150\%$$

$$I_{\sec limit} > 2.51 \; A \times 1.50$$

$$I_{\sec limit} > 3.77 \; A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~138~~144) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~139~~145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high-side~~line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (~~140~~146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (~~141~~147) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

Example Calculations: Option 14a

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (~~142~~148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~143~~149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (~~144~~150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~145~~151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

Example Calculations: Option 14a

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < \ 15.283\angle 85.0°\ \Omega$$

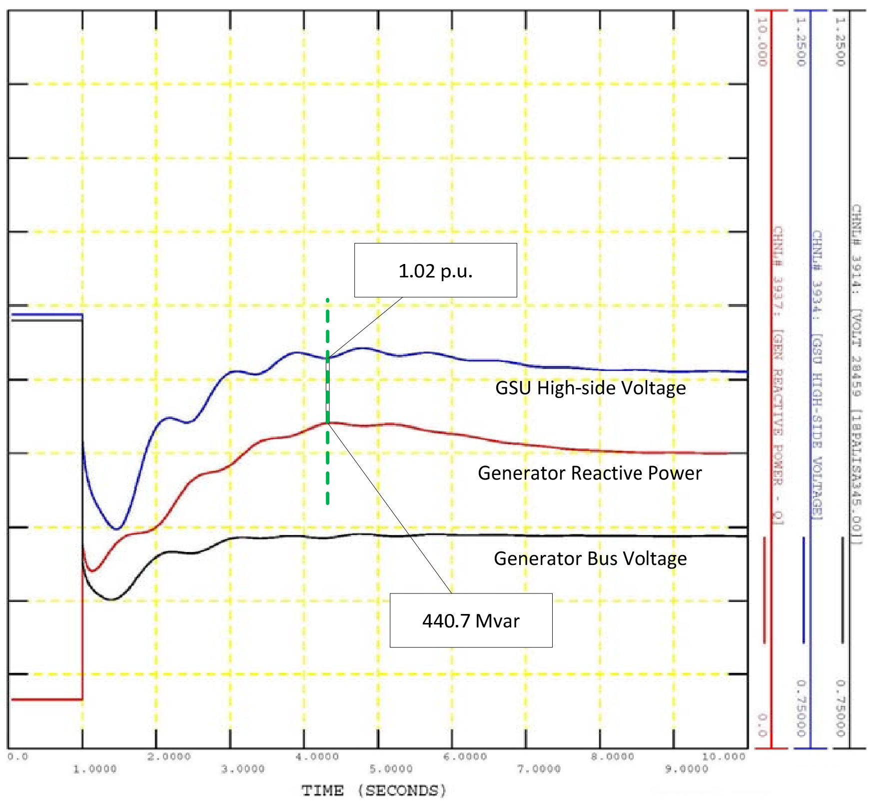
Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that~~connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, simulation is used to determine the simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and ~~high-side bus voltage~~coincident voltage for both the high-side of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~these values will correspond to the lowest apparent impedance~~.~~ at the relay location. The corresponding ~~high-side bus~~simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

Example Calculations: Option 14b



~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

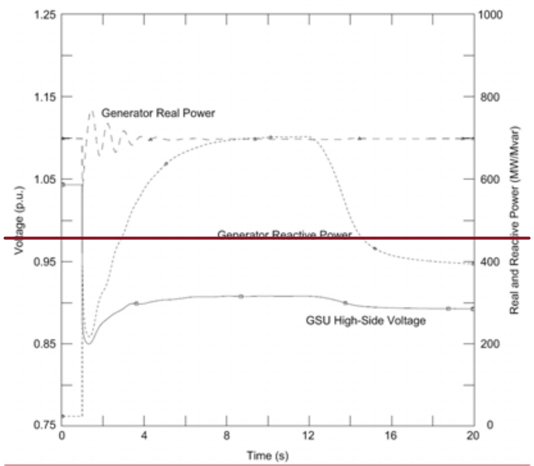
$$V_{bus} = 0.908 \times V_{nom} = 313.3\ kV$$

Formatted Table

Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~152) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (~~147~~153) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

Eq. (~~148~~154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 98.90\angle 45.1°\,\Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1°\,\Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1°\,\Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (~~149~~155) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{19.78\angle 45.1°\,\Omega}{1.15}$$

$$Z_{\sec limit} = 17.20\angle 45.1°\,\Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, then the maximum allowable impedance reach is:

Eq. (~~150~~156) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{17.20\,\Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20\,\Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0°\,\Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation~~relay installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation.

Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~installed on the high-side of the GSU transformer~~.~~, including relays installed at the remote end of the line.

Option 16a represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~directional toward the Transmission system~~–~~ installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer, including relays installed at the remote end of the line.

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer and the 0.85 per unit of the line nominal voltage at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~151~~157) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~152~~158) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

Example Calculations: Options 15a and 16a

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the high-side nominal voltage:

Formatted Table

Eq. (~~153~~159) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (~~154~~160) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (~~155~~161) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (~~156~~162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 15b:

Formatted Table

Eq. (~~157~~163) $$I_{\sec limit} > I_{sec} \times 115\%$$

Example Calculations: Options 15a and 16a

$$I_{\sec limit} > 5.701 \angle -52.8° \, A \times 1.15$$

$$I_{\sec limit} > 6.56 \angle -52.8° \, A$$

Calculations at the remote end of the line from the plant.

Formatted Table

Real Power output (P):

Eq. (164) $$P = GEN_{Synch\_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \, MW$$

$$Q = 921.12 \, Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus\_remote\_substation} = 0.85 \, p.u. \times V_{nom}$$

$$V_{bus\_remote\_substation} = 0.85 \times 345 \, kV$$

$$V_{bus\_remote\_substation} = 293.25 \, kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch\_reported} + jQ$$

$$S = 700.0 \, MW + j921.12 \, Mvar$$

$$S = 1157 \angle 52.8° \, MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_remote\_substation}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle - 52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle - 52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio\_remote\_bus}}}$$

$$I_{sec} = \frac{2280.6\angle - 52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701\ \angle - 52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 5.701\ \angle - 52.8°\ A \times 1.15$$

$$I_{\sec limit} > 6.56\ \angle - 52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~relays installed on the high-side of the GSU transformer, including relays installed at the remote end of the line, for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation.

Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~installed on the high-side of the GSU transformer~~.~~, including relays at the remote end of the line.

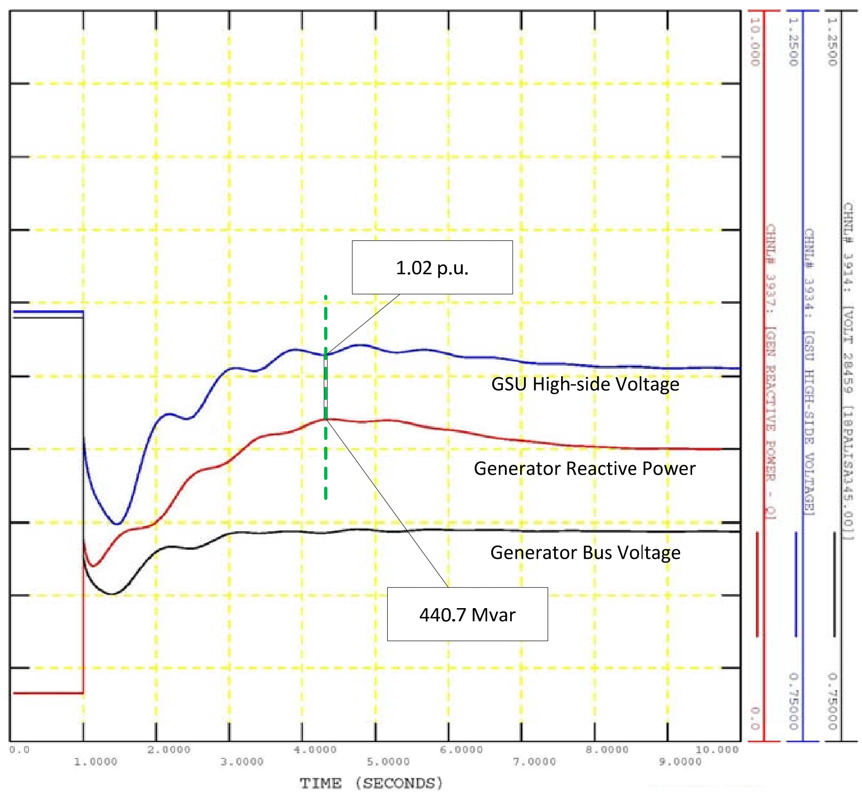
Option 16b represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications ~~–~~directional toward the Transmission system~~–~~ and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU, including relays at the remote end of the line.

~~This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU transformer.~~

Example calculations are provided for the case where relays are installed on the high-side of the GSU transformer, including relays installed on the remote end of line. Simulation is used to determine the line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing. This is achieved by modeling a shunt at the remote end (i.e., at the Transmission system) of the line during simulation.

The maximum Reactive Power flow and coincident voltage for both the high-side ~~bus voltage~~of the GSU transformer and remote end of the line are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer and remote end of the line during field-forcing is used as ~~this value~~these values will correspond to the lowest apparent impedance~~.~~ at the relay location. The corresponding ~~high-side bus~~simulated voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b



~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus\_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

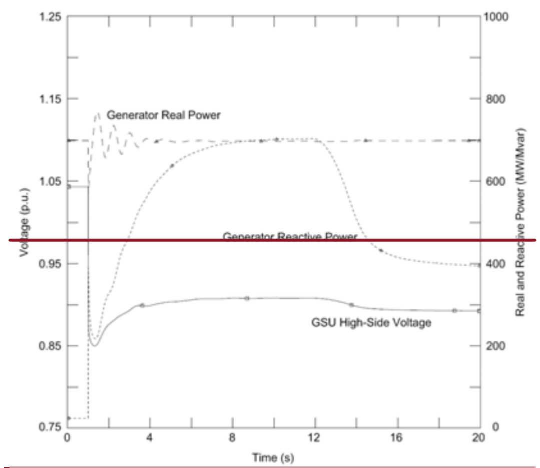
Formatted: Centered

Formatted Table

Example Calculations: Options 15b and 16b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~158~~171)
$$S = P_{Synch\_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (~~159~~172)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus\_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Example Calculations: Options 15b and 16b

Secondary current (I_{sec}):

Eq. (~~160~~173)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio\_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1°\,A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578\angle -45.1°\,A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (~~161~~174)
$$I_{\sec limit} > I_{sec} \times 115\%$$

$$I_{\sec limit} > 4.578\angle -45.1°\,A \times 1.15$$

$$I_{\sec limit} > 5.265\angle -45.1°\,A$$

Example Calculations: Option 17

Option 17 represents the calculation for three asynchronous generation Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (21) - directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~162~~175)
$$P_{Asynch} = 3 \times GEN_{Asynch\_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\,MVA \times 0.85$$

$$P_{Asynch} = 102.0\,MW$$

Reactive Power output (Q):

Eq. (~~163~~176)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

Example Calculations: Option 17

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the bus voltage (V_{bus}):

Eq. (~~164~~177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (~~165~~178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~166~~179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181) $$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\,\Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\,\Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85˚, and then the maximum allowable impedance reach is:

Eq. (~~169~~182) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\,\Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\,\Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\,\Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation Elements that connect a~~ relays on relays installed on the high-side of the GSU transformer, including relays installed on the remote end of line, for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~.

Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer, including relays at the remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer, including relays at the remote end of the line to the Transmission system that

Example Calculations: Options 18 and 19

are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~170~~183) $$P = 3 \times GEN_{Asych\_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184) $$Q = MVAR_{static} + MVAR_{gen\_static} + \left(3 \times GEN_{Asynch\_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V_{bus}):

Eq. (~~172~~185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (~~173~~186) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

Example Calculations: Options 18 and 19

$$I_{pri} = \frac{131.6\angle - 39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5\ \angle - 39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch\_ratio\_hv}}$$

$$I_{sec} = \frac{220.5\angle - 39.2°\ A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle - 39.2°\ A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189)
$$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.675\angle - 39.2°\ A \times 1.30$$

$$I_{\sec limit} > 4.778\angle - 39.2°\ A$$

End of calculations

Rationale~~:~~

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

Rationale for R1~~:~~

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Exhibit F

Standards Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

PRC-025 Drafting Team Roster

Project 2016-04 Modifications to PRC-025-1

	Name	Entity
Chair	John Schmall	Electric Reliability Council of Texas, Inc.
Vice Chair	Mike Jensen	Pacific Gas and Electric Company
Members	Juan Alvarez	Caithness Energy
	S. Bryan Burch, P.E.	Southern Company
	Walter Campbell	NextEra Energy Resources, LLC
	Jason Espinosa	Seminole Electric Cooperative, Inc.
PMOS Liaison	Charles Yeung	Southwest Power Pool, Inc.
NERC Staff	Scott Barfield-McGinnis, Senior Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti, Counsel	North American Electric Reliability Corporation