PRC-025-1 Guidelines and Technical Basis

Introduction

The document, "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.[1]

The term, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner ("responsible entity") 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 generationg 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 Ownerresponsible entity 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 possiblenecessary to meet this purpose by replacingreplace 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 Ownerresponsible entity 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 at the terminals of the generator, generator step-up (GSU) transformer, unit auxiliary transformer (UAT) and, where applicable, the Generator Owner's generator interconnection Facility and Elements utilized in the aggregation of dispersed power producing resources.

The drafting team recognizes that some Generator Owner'sOwners own an interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the generator step-up transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard

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[1] http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf

refs to In these cases, the Generator Owners own sole-use Facilities as "generator interconnection Facility(ies)" consistent withthat are connected to the workboundary of the Project 2010-07 (interconnected system. Load-responsive protective relays applied by the Generator RequirementsOwner at the Transmission Interface) drafting team. The following three figures clarify various considerations regarding the generator interconnection Facility.
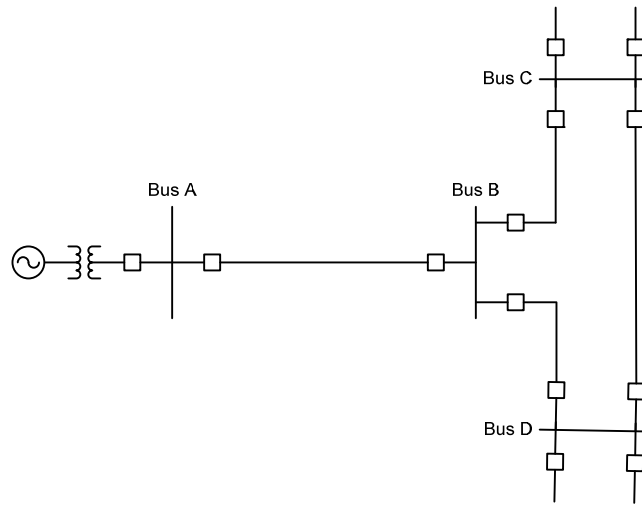

Figure 1. The line from Bus A to Bus B represents a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider or Transmission Owner owns these relays, they are responsible for them under PRC-023.
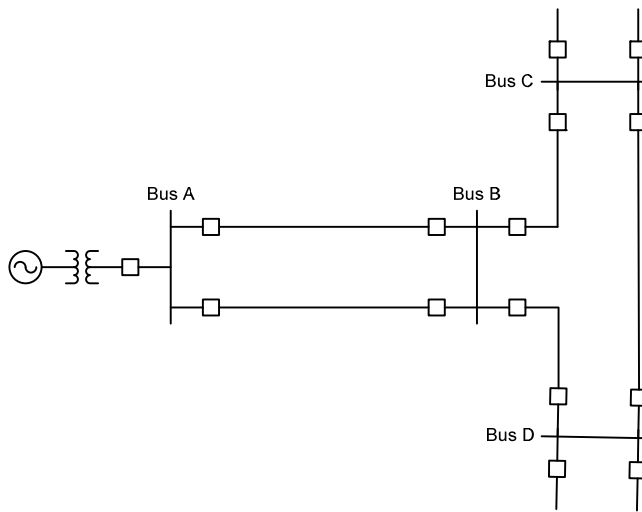

Figure 2. The parallel lines from Bus A to Bus B together represent a generator interconnection Facility. If the Generator Owner owns the load-responsive protective relays at Bus A, it would be responsible for the application of these relays under PRC-025-1. If the Distribution Provider, Generator Owner, or Transmission Owner owns these relays, they are responsible for them under PRC-023.
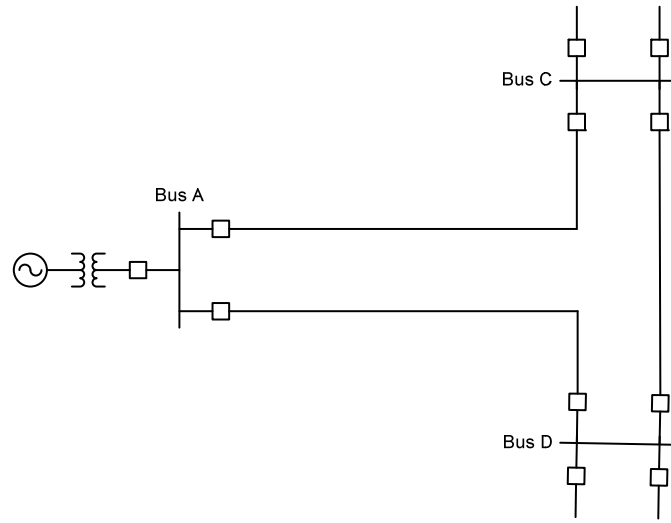
Figure 3. Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as generator interconnection Facilities. In this case, the Distribution Provider or Transmission Owner would be responsible for the load-responsive protective relays at the terminals under PRC-023.

Elements utilized~~terminals of these Facilities to protect these interconnection Facilities are included~~ 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~~scope of this~~ standard is also applicable to unit auxiliary transformers (UAT) 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 unit auxiliary transformer(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 generator step-up 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 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 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 generator step-up 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 (0.95 per unit) and 1b (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 (simulation) was developed to allow the Generator Owner~~responsible entity~~ to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

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 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 megawatts (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~~responsible entity~~ 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 the high-side of the generator step-up transformer. This can be simulated by means such as modeling the connection of a shunt reactor on the Transmission system to lower the generator step-up transformer high-side 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 or other entity as specified by the Regional Reliability Organization. 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~~megawatts as reported to the Planning Coordinator or Transmission Planner~~.

Phase Distance Relay – Directional Toward Transmission System (21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup generator step-up 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 generati~~on~~ng units or generating plants, contributing 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 overlapsrestrict 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 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 Time Overcurrent Relay (51)

See section 3.9.2 of the 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 1these 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 megavoltampere (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 synchronous or asynchronous.

Phase Time Overcurrent Relay – Voltage-Restrained (51V-R)

Phase time overcurrent voltage-restrained relays (51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup generator step-up 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 generationg 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 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 (67)

See section 3.9.2 of the 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~~are~~ similar. Note that the Table 1setting~~setting~~ criteria established within the Table 1~~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 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 synchronous or asynchronous.

Table 1, Options

Introduction

The margins in ~~the Table 1~~these options are based on guidance found in the 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 generator step-up 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, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

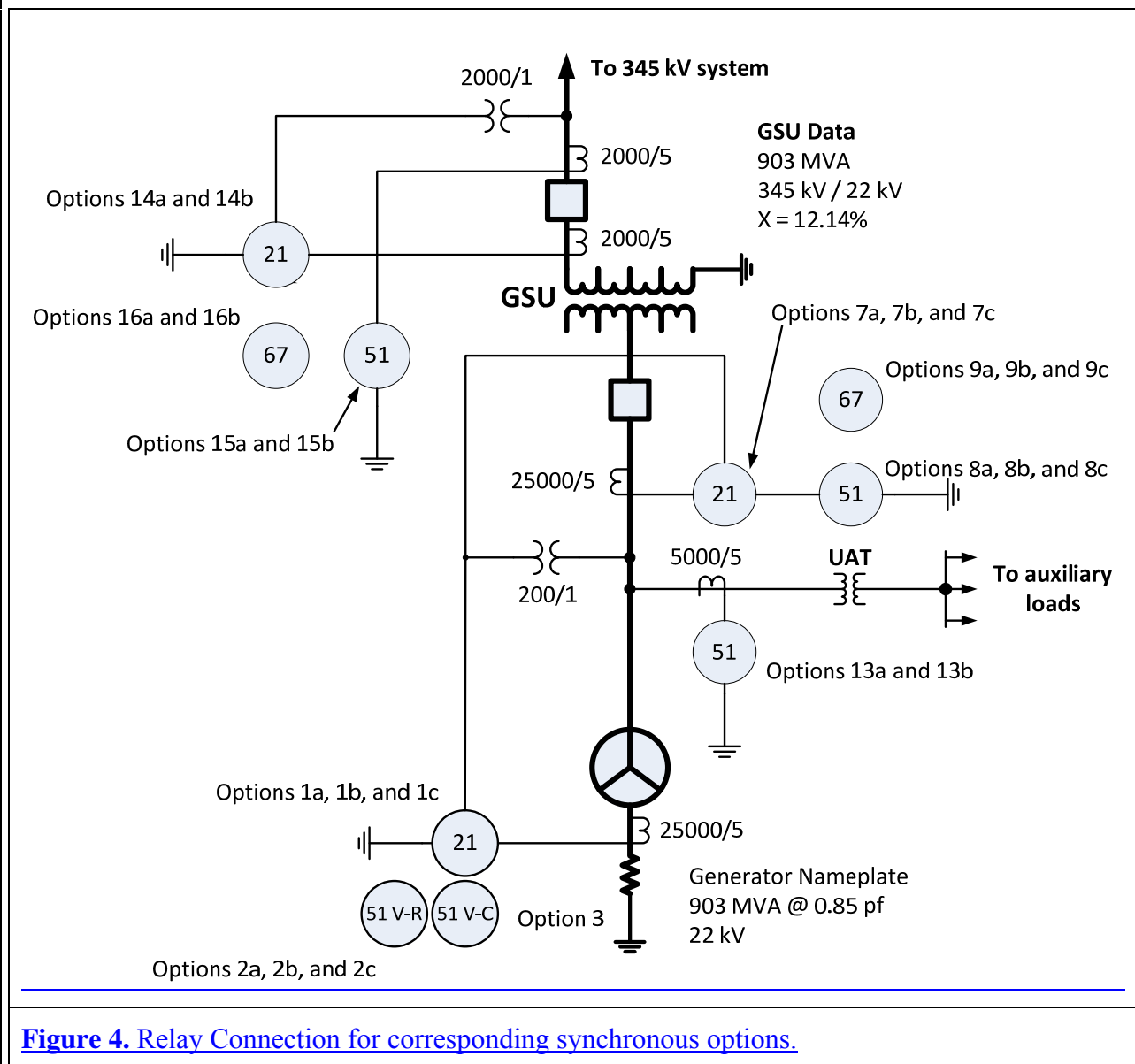**Figure 4.** Relay Connection for corresponding synchronous options.
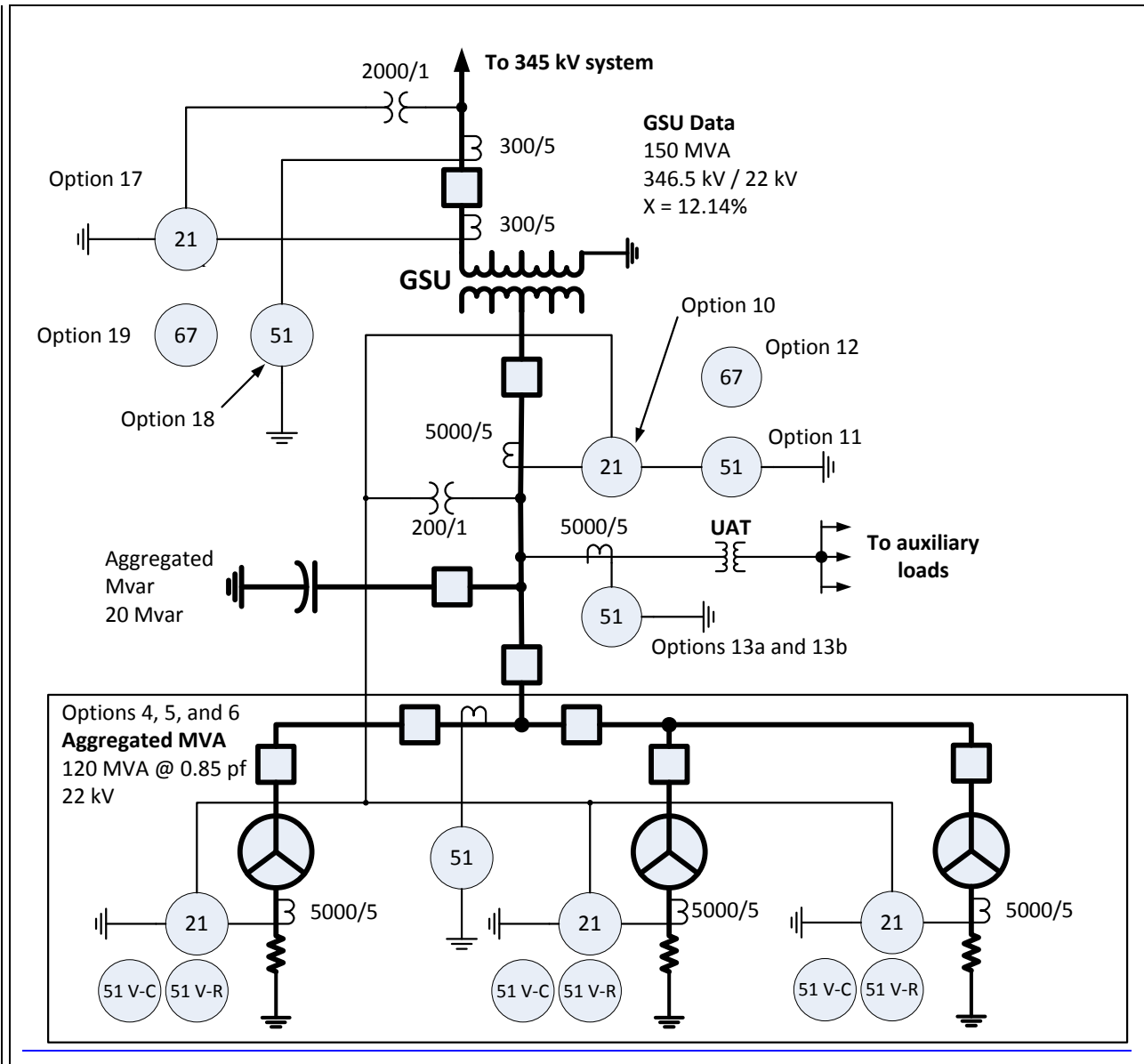
Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (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 of the 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 generator step-up transformer. The generator bus voltage is

calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates 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 generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise 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 in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up 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 set less than the calculated impedance derived from 115% of: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 1c, the impedance element is set less than the calculated impedance derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and 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-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 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 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates 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 generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at

the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise 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 in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up 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 set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the MW value, derived from the nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element is set greater than the calculated current derived from 115 percent of: the Real Power output of 100 percent of the maximum gross MW capability reported to the ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and 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 (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 of the 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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting is 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 (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 of the 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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (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~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up 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 generator step-up transformer's turns ratio.

For Option 4, the impedance element is set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (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~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up 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 generator step-up 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 ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power~~reactive power~~ devices.

This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~reactive power~~ devices that contribute to the power flow through the relay.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (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 of the 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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting is 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 (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 generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission system on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up 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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates 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 generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise 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 in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing.~~.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 7a and 7b 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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, 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 Time Overcurrent Relay (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 generator step-up 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 generator step-up transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the~~or~~ high-side of the generator step-up transformer, use Option 15 ~~of a synchronous generator~~.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the

generator step-up transformer times the turns ratio of the generator step-up transformer (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 generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up 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~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up 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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the 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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, 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 generator step-up 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 generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of a synchronous generator. Where the relay is connected on the high-side of the generator step-up 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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (excluding the impedance). This is the simplest calculation that approximates 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 generator step-up transformer. The voltage drop across the generator step-up transformer is calculated based on a 0.85 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer and accounts for the turns ratio and impedance of the generator step-up transformer. The actual generator bus voltage may be higher depending on the generator step-up transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a~~corresponding to~~ 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing.~~.~~ Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 9a and 9b, 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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor.

For Option 9c, 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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization, 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 (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (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 generator step-up transformers. Table 1, Option 10 is provided for assessing loadability for generator step-up transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the generator step-up transformer of an asynchronous generator. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Where the relay is connected on the high-side of the generator step-up 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 generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the

generator step-up transformer times the turns ratio of the generator step-up transformer (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~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up 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 generator step-up transformer's turns ratio.

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

Generator Step-up Transformer (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 11~~Options 11a and 11b~~)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on generator step-up 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~~11a, address those~~ generator step-up transformers applying~~transformer~~ phase time overcurrent relays ~~installed~~ on asynchronous generators that are connected to the ~~low-side (i.e.,~~generator-side~~)~~ of the generator step-up transformer. Where the relay is connected ~~of an asynchronous generator, and Option 11b addresses those relays installed~~ on the high-side ~~(i.e., line-side)~~ of the generator step-up transformer, use Option 18~~of an asynchronous generator~~.

Option 11~~11a~~ calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer.~~ for overcurrent relays installed on the low-side.~~ The generator bus voltage ~~drop across the generator step-up transformer~~ is calculated by multiplying~~based on~~ a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times~~and accounts for~~ the turns ratio of the generator step-up transformer (excluding the impedance).~~ This is a simple calculation that approximates the stressed system conditions.

Since~~Where~~ the relay current is supplied from the generator bus, ~~Option 11a,~~ it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up 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 generator step-up transformer's turns ratio. ~~Where the relay current is supplied from the high-side of the transformer, it is necessary to assess loadability using the high-side nominal voltage in Option 11b.~~

For Option 11~~Options 11a and 11b~~, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic <u>Reactive Power</u>~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic <u>Reactive Power</u>~~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 generator step-up 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 <u>nameplate</u> 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 generator step-up transformers applying phase directional time overcurrent relays directional toward the Transmission System <u>on asynchronous generators</u> that are connected to the generator-side of the generator step-up transformer of an asynchronous generator<u>. Where the relay is connected on the high-side of the generator step-up transformer, use Option 19</u>.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer. The generator bus voltage is calculated by multiplying a 1.0 per unit ~~system~~ nominal voltage at the high-side terminals of the generator step-up transformer times the turns ratio of the generator step-up transformer (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 <u>Reactive Power</u>~~reactive power~~ as synchronous generators; the voltage drop due to <u>Reactive Power</u>~~reactive power~~ flow through the generator step-up 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 generator step-up 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 ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic <u>Reactive Power</u>~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic <u>Reactive Power</u>~~reactive power~~ devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Time Overcurrent Relay (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 unit auxiliary transformer(s) ("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 protecting 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 relaysing applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard. Phase time overcurrent relaying applied to the UAT that results in a generator runback are not a part of this standard. Although the UAT is not directly in the output path from the generator to the 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-61 – Auxiliary Power System (independent from generator).)

Figure-72 – 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 UAT load demand at the highest generator output. Although the 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 (13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer time overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b calculate the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding or each low-side winding of the UAT based on relay location. Consideration of the voltage drop across the transformer is not necessary.

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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization. This allows for a reduced setting pickup compared to Option 13a but does allow for an entity's relay setting philosophy. Because loading characteristics may be different from one load bus to another, the phase current measurement will have to be verified at each relay location. The phase time overcurrent relay pickup setting criteria is established at 150 percent of the measured value for each relay location. 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 ~~Planning Coordinator or~~ Transmission Planner or other entity as specified by the Regional Reliability Organization.

The performance of the UAT loads during stressed system conditions (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%) and use a generator bus voltage of 1.0 per unit. A minimum pickup current based on 150 percent of maximum 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.

Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 14 is used for these relay as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 14a reflectsand 14b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the impedance value used for applying the generator interconnection Facilitiesstep-up transformer 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 voltage. Consideration of the voltage drop across the generator step-up 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 generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, 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 Planning Coordinator or Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, 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 Planning Coordinator or Transmission Planner or other entity as specified by the Regional Reliability Organization, and 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.

Generator Interconnection Facilities (Synchronous Generators) Phase Time Overcurrent Relay (51) (Options 15a and 15b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up 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. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 15 is used for these relay as well.

Table 1, Options 15a and 15b, establish criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 15a reflectsand 15b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the generator interconnection Facilitiesstep-up transformer phase time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit Transmission system voltage. Consideration of the voltage drop across the generator step-up 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 generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, 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 Planning Coordinator or Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, 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 Planning Coordinator or Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120100 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.

Generator Interconnection Facilities (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 16a and 16b)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up 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. Relays applied on the high-side of the generator step-up transformer respond to the same quantities as the relays connected on the generator interconnection Facilities, thus Option 16 is used for these relay 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 generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Options 16a reflectsand 16b, reflect a 0.85 per unit Transmission system voltage; therefore, establishing that the current value used for applying the interconnection Facilitiesgenerator step-up transformer 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 voltage. Consideration of the voltage drop across the generator step-up 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 generator step-up transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, 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 Planning Coordinator or Transmission Planner or other entity as specified by the Regional Reliability Organization, and Reactive Power output that equates to 120150 percent of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, 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 Planning Coordinator or Transmission Planner or other entity as specified by the Regional Reliability Organization, and 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.

Generator Interconnection Facilities (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (21) (Option 17)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up transformers. These margins are based on guidance found in section 3.1 of the 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 generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the impedance from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Powerreactive power as synchronous generators; the voltage drop due to Reactive Powerreactive power flow through the generator step-up transformer is not as significant.

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

Generator Interconnection Facilities (Asynchronous Generators) Phase Time Overcurrent Relay (51) (Option 18)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up 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 18 establishes criteria for phase time overcurrent relays to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Powerreactive power as synchronous generators; the voltage drop due to Reactive Powerreactive power flow through the generator step-up transformer is not as significant.

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

Generator Interconnection Facilities (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 19)

Relays applied on generator interconnection Facilities are challenged by loading conditions similar to relays applied on generators and generator step-up 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 19 establishes criteria for phase directional time overcurrent relays that are directional toward the Transmission system to prevent generator interconnection Facilities from operating during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit nominal voltage on the high-side terminals of the generator step-up transformer to calculate the current from the maximum aggregate nameplate MVA. Asynchronous generators do not produce as much Reactive Power~~reactive power~~ as synchronous generators; the voltage drop due to Reactive Power~~reactive power~~ flow through the generator step-up transformer is not as significant.

For Option 19, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate ~~megavoltampere (~~MVA~~)~~ output at rated power factor including the Mvar output of any static or dynamic Reactive Power ~~reactive power~~ devices. This is determined by summing the total ~~nameplate~~ MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power~~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**
Generator nameplate (MVA @ rated pf):	$GEN_{Synch\_nameplate}$ ~~$GEN_{nameplate}$~~ $= 903\ MVA$ $pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen\ nom}$~~V_{gen}~~ $= 22\ kV$
Real Power output in MW as reported to the PC or TP:	$P_{reported} = 700.0$~~767.6~~ MW
Generator step-up transformer rating:	$MVA_{GSU} = 903\ MVA$
Generator step-up transformer impedance (903 MVA base):	$Z_{gsu} = 12.14\%$
Generator step-up transformer MVA base:	$MVA_{base} = 767.6\ MVA$
Generator step-up transformer turns ratio:	$GSU_{ratio} = \dfrac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer ratio:	$CT_{ratio} = \dfrac{25000}{5}$
Potential transformer ratio low-side:	$PT_{ratio} = \dfrac{200}{1}$
Potential transformer ratio high-side:	$PT_{ratio\_hv} = \dfrac{2000}{1}$
Auxiliary transformer nameplate:	$UAT_{nameplate} = 60\ MVA$
Auxiliary low-side voltage:	$V_{uat} = 13.8\ kV$
Auxiliary current transformer:	$CT_{uat} = \dfrac{5000}{5}$
Current transformer~~Transformer~~ High Voltage CT ratio:	CT_{ratio_hv}~~CT_{HV}~~ $= \dfrac{2000}{5}$
Reactive p~~P~~ower output of static reactive device:	$MVAR_{static} = 20$~~100~~ $Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch\_nameplate} = 120\ MVA$

Example Calculations.	
	$pf = 0.85$
Asynchronous current transformer ratio:	$CT_{Asynch\_ratio} = \dfrac{5000}{5}$
Asynchronous current transformer High Voltage CT ratio:	$CT_{Asynch\_ratio\_hv} = \dfrac{300}{5}$

Example Calculations: Option 1a

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

Real Power output (P):

Eq. (1) $\quad P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$

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

$\quad P = 767.6\ MW$

Reactive Power output (Q):

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

$\quad Q = 1.5 \times 767.6\ MW$

$\quad Q = 1151.3\ Mvar$

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) $\quad V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}\cancel{GSU_{ratio}}$

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

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

Apparent power (S):

Eq. (4) $\quad S = P_{reported} + jQ$

$\quad S = 700.0\cancel{767.6}\ MW + j1151.3\ Mvar$

$\quad S = 1347.4\angle58\cancel{1383.7\angle56.3}°\ MVA$

Primary impedance (Z_{pri}):

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

$\quad Z_{pri} = \dfrac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}\cancel{\dfrac{(20.81\ kV)^2}{1383.7\angle -56.3°\ MVA}}$

$\quad Z_{pri} = 0.321\angle58.73\cancel{130\angle56.3}°\ \Omega$

Example Calculations: Option 1a

Secondary impedance (Z_{sec}):

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

$$Z_{sec} = 0.321\angle 58.7\cancel{3130\angle 56.3}° \, \Omega \times \dfrac{\frac{25000}{5}}{\frac{200}{1}} \cancel{\dfrac{\frac{25000}{5}}{\frac{200}{1}}}$$

$$Z_{sec} = 0.321\angle 58.7\cancel{3130\angle 56.3}° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7\cancel{.8238\angle 56.3}° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $\quad Z_{sec\,limit} = \dfrac{Z_{sec}}{115\%}$

$$Z_{sec\,limit} = \dfrac{8.035\angle 58.7°\Omega}{1.15} \quad \cancel{\dfrac{7.8238\angle 56.3°\,\Omega}{1.15}}$$

$$Z_{sec\,limit} = 6.9873\angle 58.7\cancel{8033\angle 56.3}° \, \Omega$$

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

Eq. (8) $\quad Z_{max} < \dfrac{|Z_{sec\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\,load\,angle}\right)}$

$$Z_{max} < \dfrac{6.9873\Omega}{\cos(85.0° - 58.7°)} \quad \cancel{\dfrac{6.8033\,\Omega}{\cos(85.0° - 56.3°)}}$$

$$Z_{max} < \dfrac{6.9873\,\Omega}{0.896} \quad \cancel{\dfrac{6.8033\,\Omega}{0.8771}}$$

$$Z_{max} < 7.793\cancel{7561}\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

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

Real Power output (P):

Eq. (9) $\quad P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$

Example Calculations: Options 1b and 7b

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

$$P = 767.6\ MW$$

Reactive Power output (Q):

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

$$Q = 1.5 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base:

Real Power output (P):

Eq. (11)
$$P_{pu} = \frac{P_{reported}}{MVA_{base}} \frac{\cancel{P}}{\cancel{MVA_{base}}}$$

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

$$P_{pu} = \cancel{1}0.91\ p.u.$$

Reactive Power output (Q):

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

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

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

Transformer impedance (X_{pu}):

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

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

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

Example Calculations: Options 1b and 7b

Use the formula below; calculate the low-side ~~GSU~~generator step up 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~~Repeat~~ the calculation as~~if~~ necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14)

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

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right] \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8075}$$

$$\theta_{low-side} = 6.7\cancel{3}°$$

Eq. (15)

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

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

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2} \frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3°)}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2} \frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2} \frac{0.8430 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.999\underline{9}\cancel{8}1 \ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.999\underline{9}\cancel{8}1 per unit for the second iteration:

Eq. (16)

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

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right] \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}$$

Example Calculations: Options 1b and 7b

$\theta_{low-side} = 6.3°$

~~5.92°~~
~~0.8484~~

~~$\theta_{low-side} = 7.0°$~~

Eq. (17)
$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2} {\sout{|V_{low-side}|}}$$

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

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2} {\sout{\frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0°}}{2}}}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2} {\sout{\frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}}}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2} {\sout{\frac{0.8437 \pm 1.1532}{2}}}$$

$$|V_{low-side}| = 0.9998\text{7}\; p.u.$$

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

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

$$V_{bus} = 0.9998\text{7}\; p.u.\; \times 345\; kV \times \left(\frac{22\; kV}{346.5\; kV}\right)$$

$$V_{bus} = 21.90\text{88}\; kV$$

Apparent power (S):

Eq. (19)
$$S = P_{reported} + jQ$$

$$S = 700.0\text{767.6}\; MW + j1151.3\; Mvar$$

$$S = 1347.4\angle58\text{1383.7}\angle56.3°$$

Example Calculations: Options 1b and 7b

Primary Impedance (Z_{pri}):

Eq. (20)

$$Z_{pri} = \frac{V_{bus}^2}{S^*} \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90 \; kV)^2}{1347.4\angle -58.7° \; MVA} \frac{(21.88 \; kV)^2}{1383.7\angle -56.3° \; MVA}$$

$$Z_{pri} = 0.356\angle 58.7\text{3458}\angle\text{56.3}° \; \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21)

$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7\text{3458}\angle\text{56.3}° \; \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}} \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7\text{3458}\angle\text{56.3}° \; \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7\text{6462}\angle\text{56.3}° \; \Omega$$

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

Eq. (22)

$$Z_{sec\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec\,limit} = \frac{8.900\angle 58.7° \; \Omega}{1.15} \frac{8.6462\angle 56.3° \; \Omega}{1.15}$$

$$Z_{sec\,limit} = 7.74\angle 58.7\text{5185}\angle\text{56.3}° \; \Omega$$

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

Eq. (23)

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

$$Z_{max} < \frac{7.74\Omega}{\cos(85.0˚ - 58.7°)} \frac{7.5185\Omega}{\cos(85.0˚ - 56.3°)}$$

$$Z_{max} < \frac{7.74 \; \Omega}{0.8965} \frac{7.5185 \; \Omega}{0.8771}$$

$$Z_{max} < 8.63\text{5715}\angle 85.0° \; \Omega$$

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 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 in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

Q = 829.3 Mvar

V_{bus} = 0.990 = 21.78 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 or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported}$ = 700.0 MW~~This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.~~

Apparent power (S):

Eq. (24) $S = P_{reported} + jQ$

$S = 700.0 \, MW + j829.3 \, Mvar$

$S = 1085.2 \angle 49.8°$

Example Calculations: Options 1c and 7c

Primary Impedance (Z_{pri}):

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

$$Z_{pri} = \frac{(21.78\ kV)^2}{1085.2\angle -49.8°\ MVA}$$

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

Secondary impedance (Z_{sec}):

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

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

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

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

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

Eq. (27) $\quad Z_{sec\,limit} = \dfrac{Z_{sec}}{115\%}$

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

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

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

Eq. (28) $\quad Z_{max} < \dfrac{|Z_{sec\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\,load\,angle}\right)}$

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

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

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

Example Calculations: Option 2a

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (29~~24~~) $P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$

$P = 903\ MVA\ \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (30~~25~~) $Q = 150\% \times P$

$Q = 1.5 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

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~~26~~) $V_{gen} = 0.95\ p.u.\ \times V_{nom} \times GSU_{ratio}$

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

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (32~~27~~) $S = P_{reported} + jQ$

$S = 700.0\cancel{767.6}\ MW + j1151.3\ Mvar$

$S = 1347.4\angle58\cancel{1383.7\angle56.3}° \ MVA$

Primary current (I_{pri}):

Eq. (33~~28~~) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \dfrac{1347.4\ MVA}{1.73 \times 20.81\ kV}\dfrac{\cancel{1383.7\ MVA}}{\cancel{1.73 \times 20.81\ kV}}$

$I_{pri} = 37383\cancel{38389.9}\ A$

Example Calculations: Option 2a

Secondary current (I_{sec}):

Eq. (34~~29~~)　$I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \dfrac{37383 \text{ A}}{\dfrac{25000}{5}} \; \dfrac{\cancel{38389.9 \text{ A}}}{\dfrac{\cancel{25000}}{\cancel{5}}}$$

$$I_{sec} = 7.477\cancel{678} \text{ A}$$

To satisfy the 115% margin in Option 2a:

Eq. (35~~30~~)　$I_{sec\,limit} > I_{sec} \times 115\%$

$$I_{sec\,limit} > 7.477\cancel{678} \text{ A} \times 1.15$$

$$I_{sec\,limit} > 8.59\cancel{883} \text{ A}$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase time overcurrent (51V-R) voltage restrained relay:

Real Power output (P):

Eq. (36~~3~~)　$P = GEN_{Synch\_namplate}\cancel{GEN_{namplate}} \times pf$

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

$$P = 767.6 \; MW$$

Reactive Power output (Q):

Eq. (37~~3~~)　$Q = 150\% \times P$

$$Q = 1.5 \times 767.6 \; MW$$

$$Q = 1151.3 \; Mvar$$

Example Calculations: Option 2b

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base.

Real Power output (P):

Eq. (38~~3~~ 3)
$$P_{pu} = \frac{P_{reported}}{MVA_{base}} \cdot \frac{P}{MVA_{base}}$$

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

$$P_{pu} = \text{1.}0.91\ p.u.$$

Reactive Power output (Q):

Eq. (39~~3~~ 4)
$$Q_{pu} = \frac{Q}{MVA_{base}}$$

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

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

Transformer impedance:

Eq. (40~~3~~ 5)
$$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

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

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

Use the formula below; calculate the low-side GSU~~generator step-up~~ 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~~Repeat~~ the calculation as~~if~~ necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41~~3~~ 6)
$$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right] \frac{\sin^{-1}(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right] \frac{\sin^{-1}(1.0 \times 0.1032)}{(0.95 \times 0.85)}$$

$$\theta_{low-side} = \frac{5.92°}{0.8075}$$

Example Calculations: Option 2b

$$\theta_{low-side} = 6.7°$$

$$\cancel{.3°}$$

Eq. (42~~3~~7)

$$|V_{low-side}|$$

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

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

$$|V_{low-side}|$$

$$= \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2} \cancel{\frac{|0.85| \times \cos(7.3°) \pm \sqrt{|0.85|^2 \times \cos(7.3}}{2}}$$

$$|V_{low-side}|$$

$$= \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2} \cancel{\frac{|0.85| \times 0.9918 \pm \sqrt{0.7225 \times 0.9837 + 0.6192}}{2}}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2} \cancel{\frac{0.8430 \pm 1.1532}{2}}$$

$$|V_{low-side}| = 0.999\underline{9}\cancel{8}1 \ p.u.$$

Use the new estimated V_low-side value of 0.999~~8~~<u>9</u>1 per unit for the second iteration:

Eq. (43~~3~~8)

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

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right] \cancel{\frac{\sin^{-1}(1.0 \times 0.1032)}{(0.9981 \times 0.85)}}$$

$$\cancel{\theta_{low-side} = \frac{5.92°}{0.8484}}$$

$$\theta_{low-side} = 6.3\underline{7}\cancel{.0}°$$

$$|V_{low-side}|$$

Eq. (44~~3~~9)

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

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

Example Calculations: Option 2b

$$|V_{low-side}|$$
$$= \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2} \frac{|0.85| \times \cos(7.0°) \pm \sqrt{|0.85|^2 \times \cos(7.0}}{2}$$

$$|V_{low-side}|$$
$$= \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2} \frac{|0.85| \times 0.9926 \pm \sqrt{0.7225 \times 0.9852 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2} \frac{0.8437 \pm 1.1532}{2}$$

$$|V_{low-side}| = 0.99987 \, p.u.$$

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

Eq. (45 ~~40~~)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.99987 \, p.u. \times 345 \, kV \times \left(\frac{22 \, kV}{346.5 \, kV}\right)$$

$$V_{bus} = 21.9088 \, kV$$

Apparent power (S):

Eq. (46 ~~41~~)
$$S = P_{reported} + jQ$$

$$S = 700.0767.6 \, MW + j1151.3 \, Mvar$$

$$S = 1347.4 \angle 581383.7 \angle 56.3° \, MVA$$

Example Calculations: Option 2b

Primary current (I$_{pri}$):

Eq. (~~47~~4 ~~2~~)

$$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV} \frac{\cancel{1383.7\ MVA}}{\cancel{1.73 \times 21.88\ kV}}$$

$$I_{pri} = 35553\cancel{36519.8}\ A$$

Secondary current (I$_{sec}$):

Eq. (~~48~~4 ~~3~~)

$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}} \frac{\cancel{36519.8\ A}}{\cancel{\frac{25000}{5}}}$$

$$I_{sec} = 7.111\cancel{304}\ A$$

To satisfy the 115% margin in Option 2b:

Eq. (~~49~~4 ~~4~~)

$$I_{sec\,limit} > I_{sec} \times 115\%$$

$$I_{sec\,limit} > 7.111\cancel{304}\ A \times 1.15$$

$$I_{sec\,limit} > 8.17\cancel{84}\ A$$

Example Calculations: Option 2c

Option 2c 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 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 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 in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

$Q = 829.3$ Mvar

$V_{bus} = 0.990 = 21.78$ 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 or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW~~This option requires simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.~~

Apparent power (S):

Eq. (50) $S = P_{reported} + jQ$

$S = 700.0 \; MW + j829.3 \; Mvar$

$S = 1085.2 \angle 49.8°$

Example Calculations: Option 2c

Primary current (I_{pri}):

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

$\qquad I_{pri} = \dfrac{1085.2\ MVA}{1.73 \times 21.78\ kV}$

$\qquad I_{pri} = 28801\ A$

Secondary current (I_{sec}):

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

$\qquad I_{sec} = \dfrac{28801\ A}{\dfrac{25000}{5}}$

$\qquad I_{sec} = 5.760\ A$

To satisfy the 115% margin in Option 2c:

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

$\qquad I_{sec\,limit} > 5.760\ A \times 1.15$

$\qquad I_{sec\,limit} > 6.624\ A$

Example Calculations: Options 3 and 6

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

Real Power output (P):

Eq. (45) $\quad P = GEN_{namplate} \times pf$

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

$\qquad P = 767.6\ MW$

Reactive Power output (Q):

Eq. (46) $\quad Q = 150\% \times P$

$\qquad Q = 1.5 \times 767.6\ MW$

Example Calculations: Options 3 and 6

$$Q = 1151.3 \, Mvar$$

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. (5447) $V_{gen} = 1.0 \, p.u. \times V_{nom} \times GSU_{ratio}$

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

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

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

Eq. (5548) $V_{setting} < V_{gen} \times 75\%$

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

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

Example Calculations: Options 4 , 10, and 1017

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. Similarly, these calculations may also be applied to other asynchronous applications, including Option 17 for generator step-up transformers and lines that radially connect a generating plant to the Transmission system. In this application it was assumed 20 Mvar100Mvar of static compensation was added.

Real Power output (P):

Eq. (5649) $P = GEN_{Asych\_namplate} GEN_{namplate} \times pf$

$$P = 120903 \, MVA \times 0.85$$

$$P = 102.0767.6 \, MW$$

Reactive Power output (Q):

Eq. (5750) $Q = MVAR_{static} + GEN_{Async\_namplate} GEN_{namplate} \times \sin(\cos^{-1}(pf))$

$$Q = 20100 \, Mvar + 63.2 \, Mvar \times 475.7 \, Mva$$

$$Q = 83.2575.7 \, Mvar$$

Options 4, 10, and 1017, 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. (5851) $V_{gen} = 1.0 \, p.u. \times V_{nom} \times GSU_{ratio}$

Example Calculations: Options 4 ~~, 10,~~ and 10~~17~~

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

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

Apparent power (S):

Eq. (59~~52~~) $S = P + \text{\sout{$P_{reported}$}} + jQ$

$$S = 102.0\text{\sout{767.6}} \; MW + j83.2\text{\sout{j575.7}} \; Mvar$$

$$S = 131.6\angle 39.2\text{\sout{959.5$\angle$36.9}}° \; MVA$$

~~$\theta_{transient\ load\ angle} = 36.9°$~~

Primary impedance (Z$_{pri}$):

Eq. (60~~53~~) $Z_{pri} = \dfrac{V_{gen}^2}{S^*}$

$$Z_{pri} = \frac{(21.9 \; kV)^2}{131.6\angle -39.2° \; MVA} \; \text{\sout{$\frac{(21.9\ kV)^2}{959.5\angle-36.9°\ MVA}$}}$$

$$Z_{pri} = 3.644 \; \angle 39.2\text{\sout{0.5001$\angle$36.9}}° \; \Omega$$

Secondary impedance (Z$_{sec}$):

Eq. (61~~54~~) $Z_{sec} = Z_{pri} \times \dfrac{CT_{Asynch\_ratio} \; \text{\sout{CT_{ratio}}}}{PT_{ratio} \; \text{\sout{PT_{ratio}}}}$

$$Z_{sec} = 3.644 \; \angle 39.2°\text{\sout{0.5001$\angle$36.9}} \; \Omega \times \frac{\frac{5000}{5} \; \text{\sout{$\frac{25000}{5}$}}}{\frac{200}{1} \; \text{\sout{$\frac{200}{1}$}}}$$

$$Z_{sec} = 3.644 \; \angle 39.2\text{\sout{0.5001$\angle$36.9}}° \; \Omega \times 5\text{\sout{25}}$$

$$Z_{sec} = 18.22 \; \angle 39.2\text{\sout{12.502$\angle$36.9}}° \; \Omega$$

To satisfy the 130% margin in Option 4~~1a~~:

Eq. (62~~55~~) $Z_{\sec\, limit} = \dfrac{Z_{sec}}{130\%}$

$$Z_{\sec\, limit} = \frac{18.22\angle 39.2° \; \Omega}{1.30} \; \text{\sout{$\frac{12.502\angle36.9°\ \Omega}{1.30}$}}$$

$$Z_{\sec\, limit} = 14.02\angle 39.2\text{\sout{9.617$\angle$36.9}}° \; \Omega$$

Example Calculations: Options 4 ~~, 10,~~ and 10~~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. (63~~56~~) $Z_{max} < \dfrac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\,load\,angle})}$ ~~$Z_{max} < \dfrac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\,load\,angle})}$~~

$Z_{max} < \dfrac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$ ~~$\dfrac{9.617\ \Omega}{\cos(85.0° - 36.9°)}$~~

$Z_{max} < \dfrac{14.02\ \Omega}{0.6972}$ ~~$\dfrac{9.617\ \Omega}{0.6678}$~~

$Z_{max} < 20.109$~~14.401~~$\angle 85.0°\ \Omega$

Example Calculations: Option 5

This represents the calculation for asynchronous generators applying a phase time overcurrent (51V-R) – voltage restrained relay. In this application it was assumed 2~~100~~Mvar of static compensation was added. ~~Similarly, Option 6 uses the same calculation for asynchronous generators.~~

Real Power output (P):

Eq. (64~~57~~) $P = GEN_{Asynch\_namplate}$ ~~$GEN_{namplate}$~~ $\times pf$

$P = 120$~~903~~$MVA \times 0.85$

$P = 102.07$~~67.6~~MW

Reactive Power output (Q):

Eq. (65~~58~~) $Q = MVAR_{static} + GEN_{Asynch\_namplate}$ ~~$GEN_{namplate}$~~ $\times \sin(\cos^{-1}(pf))$

$Q = 20$~~100~~$Mvar + 63.24$~~75.7~~$Mvar$

$Q = 83.25$~~75.7~~$Mvar$

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~~59~~) $V_{gen} = 1.0\ p.u.\ \times V_{nom} \times GSU_{ratio}$

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

$V_{gen} = 21.9\ kV$

Example Calculations: Option 5

Apparent power (S):

Eq. ($67\cancel{60}$) $S = P + \cancel{P_{reported}} + jQ$

$$S = 102.0\cancel{767.6}\ MW + j83.2\cancel{j575.7}\ Mvar$$

$$S = 131.6\angle39.2\cancel{959.5\angle36.9}°\ MVA$$

Primary current (I_{pri}):

Eq. ($68\cancel{61}$) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{gen}}\cancel{\dfrac{S}{\sqrt{3} \times V_{gen}}}$

$$I_{pri} = \dfrac{131.6\angle-39.2°\ MVA}{1.73 \times 21.9\ kV}\ \cancel{\dfrac{959.5\ MVA}{1.73 \times 21.9\ kV}}$$

$$I_{pri} = 3473\angle-39.2°\cancel{25295.3}\ A$$

Secondary current (I_{sec}):

Eq. ($69\cancel{62}$) $I_{sec} = \dfrac{I_{pri}}{CT_{Asynch\_ratio}}\cancel{\dfrac{I_{pri}}{CT_{ratio}}}$

$$I_{sec} = \dfrac{3473\angle-39.2°\ A}{\dfrac{5000}{5}}\ \cancel{\dfrac{25295.3\ A}{\dfrac{25000}{5}}}$$

$$I_{sec} = 3.473\angle-39.2°\cancel{5.06}\ A$$

To satisfy the 130% margin in Option 5:

Eq. ($70\cancel{63}$) $I_{sec\,limit} > I_{sec} \times 130\%$

$$I_{sec\,limit} > 3.473\angle-39.2°\cancel{5.06}\ A \times 1.30$$

$$I_{sec\,limit} > 4.52\angle-39.2\cancel{6.58\angle-36.9}°\ A$$

Example Calculations: Options 7a~~Option 8a, 8b, 9a, 9b, 15a,~~ and 10~~16~~a

This represents the calculation for a mixture of asynchronous and synchronous generation (including inverter-based installations) applying a phase distance (21) – directional toward the Transmission system relay. In this application it was assumed 20 Mvar of static compensation was added. ~~Option 8a represents the calculation for a generator step-up (GSU) transformer applying a phase time overcurrent (51) relay connected to a synchronous generator. Similarly, these calculations can be applied to other synchronous generator applications, including Option 9a for generator step-up transformers applying a phase directional time overcurrent (67) directional toward the Transmission system relay, and Option 15a and 16a for lines that radially connect a generating plant to the Transmission system using a phase time overcurrent (51) and phase directional time overcurrent (67) directional toward the Transmission system relay, respectively. Options 8b and 9b use the same process, except the bus voltage is 0.85 per unit is used instead of 0.95 and excludes the generator step-up (GSU) impedance.~~

~~This example uses Option 8b as an example.~~

Synchronous Generation

Real Power output (P_{sync}):~~P):~~

Eq. (71) $P_{sync} = GEN_{Synch\_nameplate} \times pf$

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

$P_{sync} = 767.6\ MW$

$P_{sync-reported} = 700\ MW$

Reactive Power Output (Q_{sync})

Eq. (72) $Q_{sync} = 150\% \times P_{synch}$

$Q_{sync} = 150\% \times 767.6\ MW$

$Q_{sync} = 1151.3\ MW$

Apparent Power (S_{sync})

Eq. (73) $S_{sync} = P_{sync-reported} + jQ_{synch}$

$S_{sync} = 700MW + j1151.3\ MVAR$

Asynchronous

Real Power output (P_{async}):

Eq. (74~~64~~) $P_{async} = GEN_{Asynch\_namplate} \times pf$~~P = GEN_{namplate} \times pf~~

$P_{async} = 120\ MVA \times 0.85$

$P_{async} = 102.0\ MW$

Example Calculations: Options 7a~~Option 8a, 8b, 9a, 9b, 15a,~~ and 10~~16a~~

Reactive Power output (Q_{async}):

Eq. (75) $Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$

$Q_{async} = 20\ Mvar + 63.2\ Mvar$

$Q_{async} = 83.2\ Mvar$

Options 7a and 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator bus voltage, however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (V_{gen}):

Eq. (76) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

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

$V_{gen} = 20.81\ kV$

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

Eq. (77) $S = 1.15 \times \left(P_{sync-reported} + jQ_{sync} \right) + 1.30 \times \left(P_{async} + jQ_{async} \right)$

$S = 1.15 \times (700\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$

$S = 1711.8\ \angle 56.8°\ MVA$

Primary impedance (Z_{pri}):

Eq. (78) $Z_{pri} = \dfrac{V_{gen}^2}{S^*}$

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

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

Secondary impedance (Z_{sec}):

Eq. (79) $Z_{sec} = Z_{pri} \times \dfrac{CT_{ratio}}{PT_{ratio}}$

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

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

$Z_{sec} = 6.32 \angle 56.8°\ \Omega$

Example Calculations: ~~Options 7a~~Option 8a, 8b, 9a, 9b, 15a, and ~~10~~16a

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 and the asynchronous apparent power has been multiplied by 1.30 in Equation 77 to satisfy the margin requirements in Options 7a and 10:

Eq. (80) $\quad Z_{sec\,limit} = \dfrac{Z_{sec}}{100\%}$

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

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

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

Eq. (81) $\quad Z_{max} < \dfrac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\,load\,angle})}$

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

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

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

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

This represents the calculation for a mixture of asynchronous and synchronous generators applying a phase time overcurrent. In this application it was assumed 20 Mvar of static compensation was added. The CTs are located on the low-side of the GSU.

Synchronous Generation

Real Power output (P_{sync}):

Eq. (82) $\quad P_{sync} = GEN_{Synch\_nameplate} \times pf$

$$P_{sync} = 903 \, MVA \times .85$$

$$P_{sync} = 767.6 \, MW$$

$P_{sync-reported} = 700 \, MW$

Reactive Power Output (Q_{sync})

Eq. (83) $\quad Q_{sync} = 150\% \times P_{synch}$

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

$$Q_{sync} = 150\% \times 767.6 \; MW$$

$$Q_{sync} = 1151.3 \; Mvar$$

Apparent Power (S_{sync})

Eq. (84) $\quad S_{sync} = P_{sync-reported} + jQ_{synch}$

$$S_{sync} = 700 \; MW + j1151.3 \; Mvar$$

$$S_{sync} = 1347.4 \; \angle 58.7° \; MVA$$

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

Eq. (85) $\quad V_{gen} = 0.95 \; p.u. \times V_{nom} \times GSU_{ratio}$

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

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

Primary Current ($I_{pri-sync}$):

Eq. (86) $\quad I_{pri-sync} = \dfrac{1.15 \times S_{sync}^*}{\sqrt{3} \times V_{gen}}$

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

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

Asynchronous

Real Power output (P_{async}):

Eq. (87) $\quad P_{async} = \; GEN_{Asynch\_namplate} \times pf$

$$P_{async} = 120 \; MVA \; \times 0.85$$

$$P_{async} = 102.0 \; MW$$

Reactive Power output (Q_{async}):

Eq. (88) $\quad Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$

$$Q_{async} = 20 \; Mvar + 63.2 \; Mvar$$

$$Q_{async} = 83.2 \; Mvar$$

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. (89) $\quad V_{gen} = 0.95 \, p.u. \times V_{nom} \times GSU_{ratio}$

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

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

Apparent power (S_{async}):

Eq. (90) $\quad S_{async} = 1.30 \times (P_{async} + jQ_{async})$

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

$$S_{async} = 171.1 \angle 39.2° \, MVA$$

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

Eq. (91) $\quad I_{pri-async} = \dfrac{S_{Asych}}{\sqrt{3} \times V_{gen}}$

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

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

Secondary current (I_sec):

Eq. (92) $\quad I_{sec} = \dfrac{I_{pri-sync}}{CT_{ratio}} + \dfrac{I_{pri-async}}{CT_{ratio}}$

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

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

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 in Equation 86 and the asynchronous has been multiplied by 1.30 in Equation 90.

Eq. (93) $\quad I_{sec\,limit} > I_{sec} \times 100\%$

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

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

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.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU 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 in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

In this simulation the following values are derived:

$Q = 829.3$ Mvar

$V_{bus} = 0.990 = 21.78$ 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 or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW

Apparent power (S):

Eq. (94) $S = P_{reported} + jQ$

$S = 700.0\ MW + j829.3\ Mvar$

$S = 1085.2\angle49.8°$

Example Calculations: Options 8c and 9c

Primary current (I_{pri}):

Eq. (95) $I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \dfrac{1085.2 \, MVA}{1.73 \times 21.78 \, kV}$

$I_{pri} = 28801 \, A$

Secondary current (I_{sec}):

Eq. (96) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \dfrac{28801 \, A}{\dfrac{25000}{5}}$

$I_{sec} = 5.760 \, A$

To satisfy the 115% margin in Option 8c:

Eq. (97) $I_{sec\,limit} > I_{sec} \times 115\%$

$I_{sec\,limit} > 5.760 \, A \times 1.15$

$I_{sec\,limit} > 6.624 \, A$

Example Calculations: Options 11 and 12

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

Real Power output (P):

Eq. (98) $P = GEN_{Asynch\_namplate} \times pf$

$P = 120 \, MVA \times 0.85$

$P = 102.0 \, MW$

Reactive Power output (Q):

Eq. (99) $Q = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$

$Q = 20 \, Mvar + 63.2 \, Mvar$

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

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

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

Apparent power (S):

Eq. (101) $S = P + jQ$

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

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (102) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{gen}}$

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

$$I_{pri} = 3473 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (103) $I_{sec} = \dfrac{I_{pri}}{CT_{Asynch\_ratio}}$

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

$$I_{sec} = 3.473 \angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and 12:

Eq. (104) $I_{sec\,limit} > I_{sec} \times 130\%$

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

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

Example Calculations: Options 13a and 13b

Option 13a of the unit auxiliary transformer (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 or other entity as specified by the Regional Reliability Organization.

Primary current (I_{pri}):

Eq. (105) $I_{pri} = \dfrac{UAT_{nameplate}}{\sqrt{3} \times V_{uat}}$

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

$I_{pri} = 2510.2\ A$

Secondary current (I_{sec}):

Eq. (106) $I_{sec} = \dfrac{I_{pri}}{CT_{uat}}$

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

$I_{sec} = 2.51\ A$

To satisfy the 150% margin in Option 13a:

Eq. (107) $I_{sec\,limit} > I_{sec} \times 150\%$

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

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

Example Calculations: Option 14a

Option 14a represents the calculation for a synchronous generation interconnection Facility applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU.

Real Power output (P):

Eq. (108) $P = GEN_{Synch\_namplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (109~~65~~) $Q = 120\cancel{150}\% \times P$

$Q = 1.2\cancel{5} \times 767.6 \; MW$

$Q = 921.1\cancel{1151.3} \; Mvar$

Option 14a~~8b~~, 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. (110~~66~~) $V_{bus} = 0.85 \; p.u. \; \times V_{nom}$

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

$V_{gen} = 293.25 \; kV$

Apparent power (S):

Eq. (111~~67~~) $S = P_{reported} + jQ$

$S = 700.0\cancel{767.6} \; MW + j921.1\cancel{j1151.3} \; Mvar$

$S = 1157.0\angle 52.77\cancel{1383.7\angle 56.3}° \; MVA$

$\theta_{transient \; load \; angle} = 52.77°$

Primary impedance (Z_{pri}~~current (I_{pri})~~):

Eq. (112~~68~~) $Z_{pri} = \dfrac{V_{bus}^2}{S^*} \cancel{I_{pri} = \dfrac{S}{\sqrt{3} \times V_{bus}}}$

$Z_{pri} = \dfrac{(293.25 \; kV)^2}{1157.0\angle -52.77° \; MVA} \cancel{I_{pri} = \dfrac{1383.7 \; MVA}{1.73 \times 293.25 \; kV}}$

$Z_{pri} = 74.335\angle 52.77° \; \Omega \cancel{I_{pri} = 2724.3 \; A}$

Secondary impedance (Z_{sec}~~current (I_{sec})~~):

Eq. (113~~69~~) $Z_{sec} = Z_{pri} \times \dfrac{CT_{hv}}{PT_{hv}} \cancel{I_{sec} = \dfrac{I_{pri}}{CT_{ratio}}}$

$Z_{sec} = 74.335\angle 52.77° \; \Omega \times \dfrac{\frac{2000}{5}}{\frac{2000}{1}} \cancel{I_{sec} = \dfrac{2724.3 \; A}{\frac{25000}{5}}}$

$Z_{sec} = 74.335\angle 52.77° \; \Omega \times 0.2 \cancel{I_{sec} = 0.545 \; A}$

$Z_{sec} = 14.867\angle 52.77° \; \Omega$

Example Calculations: Option 14a

To satisfy the 115% margin in Option 14a8a:

Eq. (11470) $Z_{\sec limit} = \dfrac{Z_{sec}}{115\%} I_{sec limit} > I_{sec} \times 115\%$

$$Z_{\sec limit} = \frac{14.867\angle 52.77° \ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77° \ \Omega$$

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

Eq. (115) $Z_{max} < \dfrac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$

$$Z_{max} < \frac{12.928\Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928 \ \Omega}{0.846}$$

$$Z_{max} < \ 15.283\angle 85.0° \ \Omega$$

$I_{sec limit} > 0.545 \ A \times 1.15$

$I_{sec limit} > 0.627 \ A$

Example Calculations: OptionOptions 7c, 8c, 9c 14b, 15b, and 16b

Option 14b represents the simulation for a synchronous generation interconnection Facility applying a phase distance (21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU.

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 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 in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.

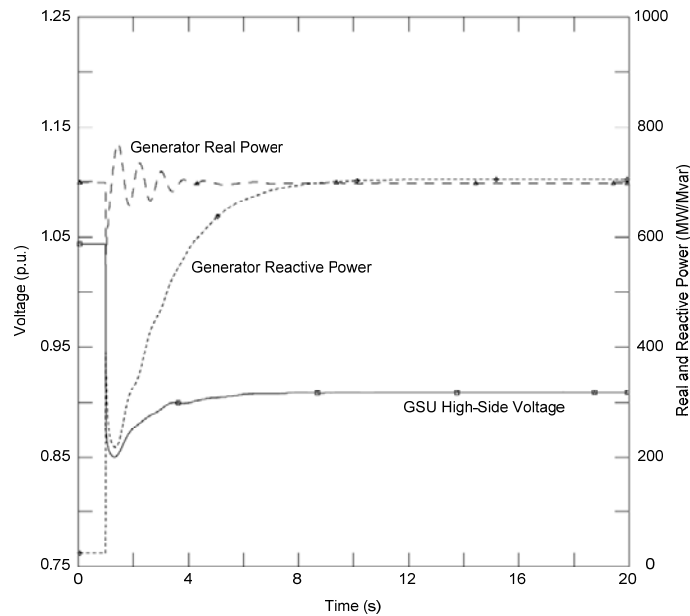In this simulation the following values are derived:

$Q = 704.4$ Mvar

$V_{bus} = 0.908 = 313.3$ 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 or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MWThese options require simulation. Refer to the Machine Data at the beginning of this section for inputs and the Guidelines and Technical Basis for other pertinent information.

> **Example Calculations:** ~~Option~~Options 7e, 8e, 9e **14b, ~~15b, and 16b~~**

Apparent power (S):

Eq. (116) $S = P_{reported} + jQ$

$S = 700.0\ MW + j704.4\ Mvar$

$S = 993.1\angle 45.2°\ MVA$

$\theta_{transient\ load\ angle} = 45.2°$

Primary impedance (Z_{pri}):

Eq. (117) $Z_{pri} = \dfrac{V_{bus}^2}{S^*}$

$Z_{pri} = \dfrac{(313.3\ kV)^2}{993.1\angle - 45.2°\ MVA}$

$Z_{pri} = 98.84\angle 45.2°\ \Omega$

Secondary impedance (Z_{sec}):

Eq. (118) $Z_{sec} = Z_{pri} \times \dfrac{CT_{hv}}{PT_{hv}}$

$Z_{sec} = 98.84\angle 45.2°\ \Omega \times \dfrac{\frac{2000}{5}}{\frac{2000}{1}}$

$Z_{sec} = 98.84\angle 45.2°\ \Omega \times 0.2$

Example Calculations: ~~Option~~Options 7e, 8e, 9e 14b~~, 15b, and 16b~~

$$Z_{sec} = 19.77 \angle 45.2° \, \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (119)
$$Z_{sec \, limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{sec \, limit} = \frac{19.77 \angle 45.2° \, \Omega}{1.15}$$

$$Z_{sec \, limit} = 17.19 \angle 45.2° \, \Omega$$

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

Eq. (120)
$$Z_{max} < \frac{|Z_{sec \, limit}|}{\cos(\theta_{MTA} - \theta_{transient \, load \, angle})}$$

$$Z_{max} < \frac{17.19 \, \Omega}{\cos(85.0° - 45.2°)}$$

$$Z_{max} < \frac{17.19 \, \Omega}{0.768}$$

$$Z_{max} < 22.38 \angle 85.0° \, \Omega$$

Example Calculations: Options 15a~~11a~~ **and** 16a~~12~~

This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU. ~~Option 11 represents the calculation for a generator step up (GSU) transformer applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, these calculations can be applied to Option 12 for a phase directional time overcurrent (67) directional toward the Transmission system relay. In this application it was assumed 100Mvar of static compensation was added.~~

Real Power output (P):

Eq. (121~~71~~)
$$P = GEN_{Synch\_namplate} \sim\sim GEN_{namplate} \sim\sim \times pf$$

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

$$P = 767.6 \, MW$$

Reactive Power output (Q):

Eq. (122~~72~~)
$$Q = 120\% \times P \sim\sim Q = MVAR_{static} + GEN_{namplate} \times \sin(\cos^{-1}(pf)) \sim\sim$$

$$Q = 1.2 \times 767.6 \, MW \sim\sim Q = 100 \, Mvar + 475.7 \, Mvar \sim\sim$$

Example Calculations: Options 15a~~11a~~ and 16a~~12~~

$$Q = 921.12\text{~~575.7~~}\ Mvar$$

Option 15a~~Options 11 and 12~~, Table 1 – Bus Voltage, calls for a ~~1.~~0.85 per unit of the high-side nominal voltage:~~ for the generator bus voltage (V~~gen~~):~~

Eq. (123~~73~~) $V_{bus} = \text{~~}V_{gen} = 1.\text{~~}0.85\ p.u.\ \times V_{nom}\text{~~} \times GSU_{ratio}$

$$V_{bus} = \text{~~}V_{gen} = 1.\text{~~}0.85 \times 345\ kV\text{~~} \times \left(\frac{22\ kV}{346.5\ kV}\right)\text{~~}$$

$$V_{bus} = 293.25\text{~~}V_{gen} = 21.9\text{~~}\ kV$$

Apparent power (S):

Eq. (124~~74~~) $S = P_{reported} + jQ$

$$S = 700\text{~~767.6~~}\ MW + j921.12\text{~~}j575.7\text{~~}\ Mvar$$

$$S = 1157\angle52.8\text{~~}959.5\angle36.9\text{~~}°\ MVA$$

Primary current (I$_{pri}$):

Eq. (125~~75~~) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}}\dfrac{\text{~~}S}{\text{~~}\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1157\angle-52.8°\ MVA}{1.73 \times 293.25\ kV}\frac{959.5\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 2280.6\angle-52.8°\text{~~}25295\text{~~}\ A$$

Secondary current (I$_{sec}$):

Eq. (126~~76~~) $I_{sec} = \dfrac{I_{pri}}{CT_{hv}}\dfrac{\text{~~}I_{pri}}{\text{~~}CT_{ratio}}$

$$I_{sec} = \frac{2280.6\angle-52.8°\ A}{\dfrac{2000}{5}}\frac{25295\ A}{\dfrac{25000}{5}}$$

$$I_{sec} = 5.701\ \angle-52.8°\text{~~}059\text{~~}\ A$$

To satisfy the 115~~130~~% margin in Option 15a~~Options 11 and12~~:

Eq. (127~~77~~) $I_{sec\,limit} > I_{sec} \times 115\text{~~}130\text{~~}\%$

$$I_{sec\,limit} > 5.701\ \angle-52.8°\text{~~}059\text{~~}\ A \times 1.15\text{~~}30\text{~~}$$

$$I_{sec\,limit} > 6.56\ \angle-52.8°\text{~~}575\text{~~}\ A$$

Example Calculations: ~~Options 15bOption 13a~~ and ~~16b13b~~

This example uses Option 15b as a simulation example, where PTs and CTs are located in the high-side of the GSU.

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 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 in this example the maximum excitation limiter is not modeled. The derivation would be the same if the limiter were modeled, using the maximum Reactive Power output attained and corresponding voltage during field-forcing.
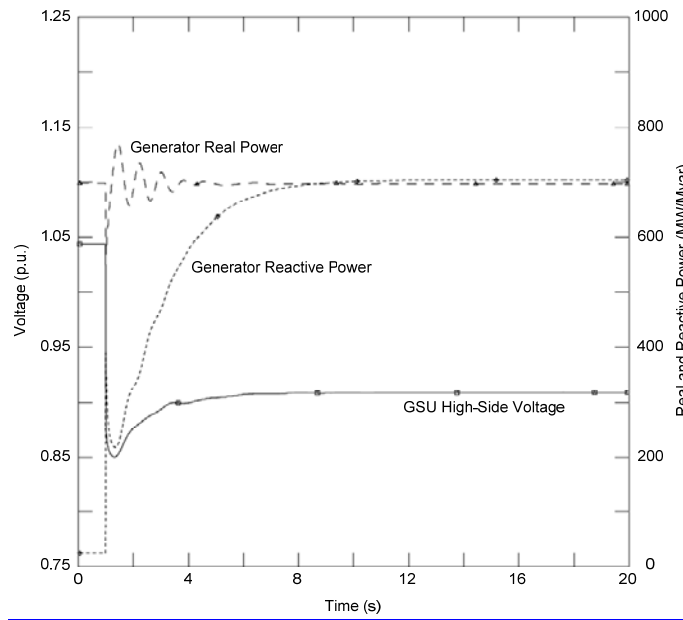
In this simulation the following values are derived:

$Q = 704.4$ Mvar

$V_{bus} = 0.908 = 313.3$ 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 or other entity as specified by the Regional Reliability Organization. In this case,

$P_{reported} = 700.0$ MW~~Option 13a of the unit auxiliary transformer (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 Planning Coordinator or Transmission Planner.~~

Apparent power (S):

Eq. (128) $S = P_{reported} + jQ$

$S = 700\ MW + j704.4\ Mvar$

$S = 993.1\angle45.2°\ MVA$

Example Calculations: Options 15bOption 13a and 16b13b

Primary current (I$_{pri}$):

Eq. (12978) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}} \dfrac{\cancel{UAT_{nameplate}}}{\cancel{\sqrt{3} \times V_{uat}}}$

$I_{pri} = \dfrac{993.1\angle -45.2° \text{ MVA}}{1.73 \times 313.3 \, kV} \dfrac{\cancel{60 \, MVA}}{\cancel{1.73 \times 13.8 \, kV}}$

$I_{pri} = 1832\cancel{2510}.2\angle -45.2° \, A$

Secondary current (I$_{sec}$):

Eq. (13079) $I_{sec} = \dfrac{I_{pri}}{CT_{ratio\_hv}} \dfrac{\cancel{I_{pri}}}{\cancel{CT_{uat}}}$

$I_{sec} = \dfrac{1832.2\angle -45.2° \text{ A}}{\dfrac{2000}{5}} \dfrac{\cancel{2510.2 \text{ A}}}{\cancel{\dfrac{5000}{5}}}$

$I_{sec} = 4.580 \angle -45.2°\cancel{.51} \text{ A}$

To satisfy the 115$\cancel{150}$% margin in Option 15b$\cancel{13a}$:

Eq. (13180) $I_{sec\,limit} > I_{sec} \times 115\cancel{150}\%$

$I_{sec\,limit} > 4.580 \angle -45.2° \times 1.15$

$I_{sec\,limit} > 5.267 \angle -45.2° \, A$

Example Calculations: Option 17

Option 17 represents the calculation for an asynchronous generation interconnection facility applying a phase distance (21) - directional toward the Transmission. In this application it was assumed 20 Mvar of static compensation was added.

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

$\cancel{I_{sec\,limit} > 3.77 \text{ A}}$

~~**Example Calculations: Option 14a**~~

~~Option 14a represents the calculation for lines that radially connect an asynchronous generating plant to the Transmission system for a phase directional time overcurrent (67) directional toward the Transmission system relay.~~

Real Power output (P):

Eq. (13~~28~~1) $P_{async} = GEN_{Asynch\_namplate} \times pf$ ~~$P = GEN_{namplate} \times pf$~~

$P_{async} = 120$~~$P = 903$~~ $MVA \times 0.85$

$P_{async} = 102.0$~~$P = 767.6$~~ MW

Reactive Power output (Q):

Eq. (13~~38~~2) $Q_{async} = MVAR_{static} + GEN_{Asynch\_namplate} \times \sin(\cos^{-1}(pf))$ ~~$Q = 150\% \times P$~~

~~$Q = 1.5 \times 767.6\ MW$~~

$Q_{async} = 20\ Mvar + 63.2$~~$Q = 1151.3$~~ $Mvar$

$Q_{async} = 83.2\ Mvar$

Option 17~~14a~~, Table 1 – Bus Voltage, calls for a 1.00~~0.85~~ per unit of the high-side nominal voltage for the bus~~generator step-up (GSU)~~ voltage (V_{bus}~~V_{nom}~~):

Eq. (13~~48~~3) $V_{bus} = 1.00$~~0.85~~ $p.u. \times V_{nom}$

$V_{gen} = 1.00$~~0.85~~ $\times 345\ kV$

$V_{gen} = 345.0$~~293.25~~ kV

Apparent power (S):

Eq. (13~~58~~4) $S = P +$ ~~$P_{reported}$~~ $+jQ$

$S = 102.0$~~767.6~~ $MW + j83.2$~~$j1151.3$~~ $Mvar$

$S = 131.6\angle39.2$~~$1383.7\angle56.3$~~ $° MVA$

~~$\theta_{transient\ load\ angle} = 56.3°$~~

Primary impedance (Z_{pri}):

Eq. (13~~68~~5) $Z_{pri} = \dfrac{V_{bus}^2}{S^*}$

$Z_{pri} = \dfrac{(345.0\ kV)^2}{131.6\angle-39.2°\ MVA}$ ~~$\dfrac{(293.25\ kV)^2}{1383.7\angle-56.3°\ MVA}$~~

$Z_{pri} = 904.4\angle39.2$~~$62.1481\angle56.3$~~ $°\ \Omega$

Secondary impedance (Z_{sec}):

Eq. (137~~86~~) $Z_{sec} = Z_{pri} \times \dfrac{CT_{Asynch\_ratio\_hv}}{PT_{ratio\_hv}} \dfrac{\cancel{CT_{ratio}}}{\cancel{PT_{ratio}}}$

$Z_{sec} = 904.4 \angle 39.2 \cancel{62.1481 \angle 56.3}° \, \Omega \times \dfrac{\frac{300}{5}}{\frac{2000}{1}} \dfrac{\cancel{\frac{25000}{5}}}{\cancel{\frac{200}{1}}}$

$Z_{sec} = 904.4 \angle 39.2° \; \cancel{62.1481 \angle 56.3°} \, \Omega \times 0.03\cancel{25}$

$Z_{sec} = 27.13 \angle 39.2 \cancel{1553.7 \angle 56.3}° \, \Omega$

To satisfy the 130~~115~~% margin in Option 17~~14a~~:

Eq. (138~~87~~) $Z_{sec\,limit} = \dfrac{Z_{sec}}{130\%} \dfrac{\cancel{Z_{sec}}}{\cancel{115\%}}$

$Z_{sec\,limit} = \dfrac{27.13 \angle 39.2° \; \Omega}{1.30} \dfrac{\cancel{1553.7 \angle 56.3° \, \Omega}}{\cancel{1.15}}$

$Z_{sec\,limit} = 20.869 \angle 39.2 \cancel{1351.0 \angle 56.3}° \, \Omega$

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

Eq. (139~~88~~) $Z_{max} < \dfrac{|Z_{sec\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\,load\,angle})}$

$Z_{max} < \dfrac{20.869 \; \Omega}{\cos(85.0° - 39.2°)} \dfrac{\cancel{1351.0 \, \Omega}}{\cancel{\cos(85.0° - 56.3°)}}$

$Z_{max} < \dfrac{20.869 \; \Omega}{0.697} \dfrac{\cancel{1651.0 \, \Omega}}{\cancel{0.8771}}$

$Z_{max} < \; 29.941 \cancel{1540.3} \angle 85.0° \, \Omega$

Example Calculations: Options ~~11b,~~ 18, and 19

Option 18~~11b~~ represents the calculation for a generation interconnection Facility~~generator step-up (GSU) transformer~~ applying a phase time overcurrent (51) relay connected to an asynchronous generator. Similarly, Option 19~~18~~ may also be applied here ~~as well for generation interconnection Facilities and Option 19~~ for the phase directional time overcurrent (67) directional toward the Transmission system relays for generation interconnection Facilities. In this application it was assumed 20~~100~~ Mvar of static compensation was added.

Real Power output (P):

Eq. (140~~89~~) $P = GEN_{Asynch\_namplate} \cancel{GEN_{namplate}} \times pf$

Example Calculations: Options ~~11b,~~ 18, and 19

$$P = 120\text{~~903~~} \, MVA \times 0.85$$

$$P = 102.0\text{~~767.6~~} \, MW$$

Reactive Power output (Q):

Eq. (14~~190~~) $Q = MVAR_{static} + GEN_{Asych\_namplate}\text{~~}GEN_{\overline{namplate}} \times \sin(\cos^{-1}(pf))$

$$Q = 20\text{~~100~~} \, Mvar + 63.24\text{~~75.7~~} \, Mvar$$

$$Q = 83.25\text{~~75.7~~} \, Mvar$$

Options ~~11b,~~ 18~~,~~ and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage (V$_{bus}$ ~~for the generator bus voltage (V~~$_{gen}$~~)~~):

Eq. (142~~91~~) $V_{nom} = 1.0 \, p.u. \times V_{nom}$

$$V_{bus}\text{~~}V_{\overline{gen}} = 1.0 \times 345 \, kV$$

$$V_{bus}\text{~~}V_{\overline{gen}} = 345 \, kV$$

Apparent power (S):

Eq. (143~~92~~) $S = P + \text{~~}P_{\overline{reported}}\text{~~} + jQ$

$$S = 102.0\text{~~767.6~~} \, MW + j83.2\text{~~}j\overline{575.7}\text{~~} \, Mvar$$

$$S = 131.6\angle39.2\text{~~959.5}\angle\overline{36.9}\text{~~}° \, MVA$$

Primary current (I$_{pri}$):

Eq. (144~~93~~) $I_{pri} = \dfrac{S^*}{\sqrt{3} \times V_{bus}} \dfrac{\overline{S}}{\sqrt{3} \times V_{\overline{gen}}}$

$$I_{pri} = \dfrac{131.6\angle-39.2° \, MVA}{1.73 \times 345 \, kV} \dfrac{\overline{959.5 \, MVA}}{\overline{1.73 \times 345 \, kV}}$$

$$I_{pri} = 220.5 \angle-39.2°\text{~~1605~~} \, A$$

Secondary current (I$_{sec}$):

Eq. (145~~94~~) $I_{sec} = \dfrac{I_{pri}}{CT_{Asynch\_ratio\_hv}} \dfrac{\overline{I_{pri}}}{\overline{CT_{HV}}}$

$$I_{sec} = \dfrac{220.5\angle-39.2° \, A}{\dfrac{300}{5}} \dfrac{\overline{1605 \, A}}{\dfrac{\overline{2000}}{\overline{5}}}$$

$$I_{sec} = 3.675\angle-39.2°\text{~~4.014~~} \, A$$

Example Calculations: Options 11b, 18, and 19

To satisfy the 130% margin in Options 11b, 18, and 19:

Eq. (14695) $I_{sec\,limit} > I_{sec} \times 130\%$

$I_{sec\,limit} > 3.675\angle - 39.2°4.014 \, \text{A} \times 1.30$

$I_{sec\,limit} > 4.778\angle - 39.2°5.218 \, \text{A}$

End of calculations