

# IEEE Guide for Protection Systems of Transmission-to-Generation Interconnections

IEEE Power and Energy Society

Sponsored by the  
Power System Relaying and Control Committee

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Power System Relaying and Control Committee  
of the  
IEEE Power and Energy Society

Approved 28 September 2017

IEEE-SA Standards Board

Abstract: This guide documents accepted protection practices for transmission-to-generation interconnections. It is intended to cover the protection system applications at the interconnections between transmission systems and generation facilities greater than 10 MVA. This guide does not cover distributed energy resources.

Keywords: generation facility, generator owner, IEEE C37.246™, interconnection, interconnection protection, point of interconnection, power system, transmission owner, transmission system

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## Introduction

This introduction is not part of IEEE Std C37.246–2017, IEEE Guide for Protection Systems of Transmission-to-Generation Interconnections.

This guide presents protection considerations for interconnections between transmission systems and generation facilities.

While some electric utilities have system protection requirements for interconnecting generation to their transmission systems, there had never been an industrywide document that incorporated commonalities between these requirements to drive application consistency. Industry deregulation, resulting in separate ownership of transmission and generation facilities, also contributed to the need for such a document. This guide should be especially beneficial for independent power producers and consulting engineers, who often design these interconnections, by providing instruction based on industry-recognized guidelines rather than on individual requirements of various utilities.

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# IEEE Guide for Protection Systems of Transmission-to-Generation Interconnections

## 1. Overview

### 1.1 Scope

This guide documents accepted protection practices for generation interconnections. It is intended to cover the protection system applications at the interconnections between transmission systems and generation facilities greater than 10 MVA. This guide does not cover distributed energy resources.

### 1.2 Purpose

This guide provides guidance to those who are responsible for the protection of electrical interconnections between transmission systems and generation facilities greater than 10 MVA. It is not intended to supplant specific transmission or generator owner practices, procedures, requirements, or any contractual agreement between the transmission and generator owners.

## 2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std C37.2™, IEEE Standard for Electrical Power System Device Functional Numbers, Acronyms, and Contact Designations.<sup>1,2</sup>

IEEE Std C37.90™, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus.

IEEE Std C37.102™, IEEE Guide for AC Generator Protection.

IEEE Std C37.113™, IEEE Guide for Protective Relay Applications to Transmission Lines.

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### 3. Definitions, acronyms, and abbreviations

#### 3.1 Definitions

For the purposes of this document, the following terms and definitions apply. The IEEE Standards Dictionary Online should be consulted for terms not defined in this clause.<sup>3</sup>

conventional power plant: A power plant utilizing one or more synchronous generators.

generation facility: A facility that produces electric energy.

generation facility relays: The protection systems used to separate a generation facility from a transmission system for faults in the generation facility and in the transmission system.

generator owner: An entity that owns or leases, with rights equivalent to ownership, a generation facility.

interconnection: The facilities that connect a transmission system to a generation facility.

point of interconnection: A switching substation where a generation facility is electrically connected to a transmission system.

tapped connection: An interconnection where a generation facility is directly connected to a transmission line.

tapped generation: A generation facility that is directly connected to a transmission line.

tie line: A transmission line dedicated to connecting a generation facility to a transmission system.

transmission owner: An entity that owns or leases, with rights equivalent to ownership, an electric transmission system.

transmission system: A high-voltage electric power system for delivering power, usually over long distance.

transmission system relays: The protection systems used to isolate faulted components of a transmission system for faults in the transmission system.

#### 3.2 Acronyms and abbreviations

CT	current transformer
DTT	direct transfer trip
GSU	generator step-up transformer
PV	photovoltaic
SSR	subsynchronous resonance
VT	voltage transformer
WTG	wind turbine generator

<sup>3</sup>IEEE Standards Dictionary Online subscription is available at <http://dictionary.ieee.org>.

## 4. Establishing interconnection

### 4.1 General design approach

When considering a design approach for transmission-to-generation interconnections, the type of new generation that is added to the system has already been selected through careful planning by the generator and transmission owners. For example, demand at various loading conditions could have necessitated a need for a gas-fired peaking plant, or new generation could be required to replace a decommissioned coal-fired unit. In addition, the state could have a clean power initiative that would involve adding a solar or wind turbine facility. The new project should go through a formal process beginning with an interconnection request. Once this has been approved through the authority having jurisdiction, a technical evaluation of the proposed interconnection should be obtained. A generation interconnection study is performed to validate the impact of the proposed generation and to identify system upgrades required to accommodate the proposed generation in order to maintain proper and reliable operation of the transmission system. There are unique modeling requirements for different types of generation, including renewable resources such as wind and solar energy, which provide intermittent output and fault current magnitude challenges versus a typical synchronous machine. The interconnection study provides technical details about not only the proposed interconnection location for the new generation facility but also the impact to other customers and the surrounding transmission system. The technical details, including power system analysis data and transmission system upgrades required for the generation interconnection, are included in the guide. The information provided in this guide should be helpful to the project as it relates to the overall design approach.

The general design approach should be coordinated between the generator and transmission owners. Typically, the design responsibility for the generator owner ends at the agreed-upon point of change of ownership between the transmission and generator owners. Considerations for the design approach as it relates to protection systems are detailed later in this guide. For example, generator ground protection needs to be coordinated with the transmission line relays. A similar philosophy is required for backup distance or voltage-controlled time overcurrent protection. Utilizing the data obtained during the information exchange is essential for the engineer. This data allows the engineer to complete the protection study for the interconnection, and this guide should help to design reliable protection schemes.

### 4.2 Information exchange and protection system characteristics

#### 4.2.1 General

Some or all of the following information needs to be exchanged between transmission and generator owners. The amount of information exchanged will be determined by the type of the interconnection.

#### 4.2.2 Transmission owner

From a transmission owner's perspective, determining the location of the point of interconnection is the first, and an important, step in the process. Once the point of interconnection is agreed upon, the station configuration and type of protection schemes can be determined. In order to define the type and characteristics (electrical and protective) of the system with which a generation facility is being interconnected, specific information is needed. This information includes the protection schemes (or proposed protection schemes) utilized to protect the transmission system where the interconnection with the generation facility occurs. Examples of line protection scheme types include directional comparison blocking, directional comparison unblocking, permissive overreaching transfer trip, permissive underreaching transfer trip, and line current differential. Other protection schemes at the transmission level include bus differential and islanding control schemes. Projected fault current levels, along with the Thevenin equivalent  $X/R$  ratios of the transmission system, available at the point of interconnection are important for determining breaker and other electrical equipment capabilities. The acceptable choice(s) for generator step-up transformer (GSU) winding connections should be specified. The relay models, settings, and instrument transformer ratios for the protection schemes should

also be proposed or specified. It is acknowledged that regional transmission authorities may have additional information exchange requirements that are applicable for specific areas and may change from time to time.

#### 4.2.2.1 Protection information

##### 4.2.2.1.1 Maximum and minimum short-circuit current

The maximum and minimum short-circuit current data is used to specify equipment installed for the interconnections with generation facilities. The transmission owner uses this data to determine the effect of resulting short-circuit current on the surrounding system and equipment, specifically, the interrupting current rating of substation circuit breakers and the short-circuit ratings of substation busses, transformers, and other equipment subjected to the increased fault current. The increased short-circuit duty affects relay settings since the increased values may cause instantaneous overcurrent elements to pick up for out-of-zone faults, speed up time overcurrent elements for relays surrounding the new generation installation, and require protection recoordination. For interconnections that provide infeed such as a tap interconnection, it could also desensitize the transmission system relays and thereby lead to an underreaching condition.

Minimum short-circuit values could be obtained for alternate switching configurations, which may be due to seasonal configuration changes or known contingency configurations used for maintenance or equipment outages. Examples of alternate configurations are opening a line terminal to help avoid seasonal overloads of the line and removing a strong source due to a fault or maintenance. These fault current values are used to set the minimum pickup for the generation facility protective relays to optimize their operation for all known contingency conditions.

##### 4.2.2.1.2 Additional considerations for faults in generator zone

Generation facility protection relays are installed with settings to separate the generation facility from the transmission system for faults in the facility and thereby minimize the effect on the surrounding system. Typical generation facility relays that provide instantaneous separation for faults within the generation facility are listed below:<sup>4</sup>

- a) 87T transformer differential relay (Figure 2 in 4.2.2.1.4 and Figure 3, Figure 4, and Figure 5 in 4.2.2.1.8)
- b) 87B bus differential relay (Figure 2)
- c) 87L line differential relay (Figure 5)

Generation facility overcurrent relaying should be coordinated with transmission protection so that faults in the generation facility zones are cleared before the transmission protection systems operate. Typical generation facility relays include transformer underreaching phase instantaneous and overreaching time overcurrent functions 50/51T. It may be necessary to consider regional regulatory requirements for relay loadability issues.

The transmission owner typically has time-delayed overreaching elements that respond to faults in the generator zone. These settings should be coordinated to allow the generator protection elements to operate and clear the faults within their zone of protection before the transmission system relays operate.

##### 4.2.2.1.3 Additional considerations for faults in transmission zone

The transmission system protection should isolate faulted components quickly to allow generation to stay online and to minimize the effects of disturbances to the generation facility.

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<sup>4</sup>Protective device numbers used in this document are defined in IEEE Std C37.2.

The generation facility protection needs to coordinate with the transmission system relays for faults in the transmission system. Typical generation facility relays used to provide backup protection for the transmission system faults are listed below:

- a) 21 phase distance (Figure 2 in 4.2.2.1.4 and Figure 3, Figure 4, and Figure 5 in 4.2.2.1.8)
- b) 51TG transformer ground overcurrent (Figure 2, Figure 3, Figure 4, and Figure 5)
- c) 67 phase directional overcurrent (Figure 2, Figure 3, and Figure 4)
- d) 67N ground directional overcurrent (Figure 2, Figure 3, and Figure 4)
- e) 51V-R voltage-restrained overcurrent (Figure 2, Figure 3, Figure 4, and Figure 5)
- f) 51V-C voltage-controlled overcurrent (Figure 2, Figure 3, Figure 4, and Figure 5)

For optimal coordination, if the phase distance function is used on the transmission system, the phase distance function should be used for generation protection. If the phase directional overcurrent function is used on the transmission system, the voltage-restrained or voltage-controlled overcurrent function should be used for generation protection.

It may be necessary to consider regional regulatory requirements for relay loadability issues.

#### 4.2.2.1.4 Example of relay coordination on interconnection

Basic relay coordination is shown in Figure 1 for the following fault conditions:

- a) Fault 1 – Generation protection should trip before CB2, CB3, CB4, or CB5 line relays.
- b) Fault 2 – Bus A differential protection should trip before CB4 or CB5 line relays. The generator relays may trip as backup protection. Bus B relays may trip as backup protection for a failed CB2 or CB3 breaker or bus differential relays.
- c) Fault 3 Normal configuration – Line relays associated with CB3 and CB5 should trip and isolate the fault.
- d) Fault 3 Alternate configuration – With Line 1 out of service, a fault on Line 2 should be detected and cleared by CB3 line relays and CB5 line relays. However, since Line 1 is out of service and there may not be enough coordination margin between the line and generator protection, it may be acceptable to trip CB1 for Line 2 fault.

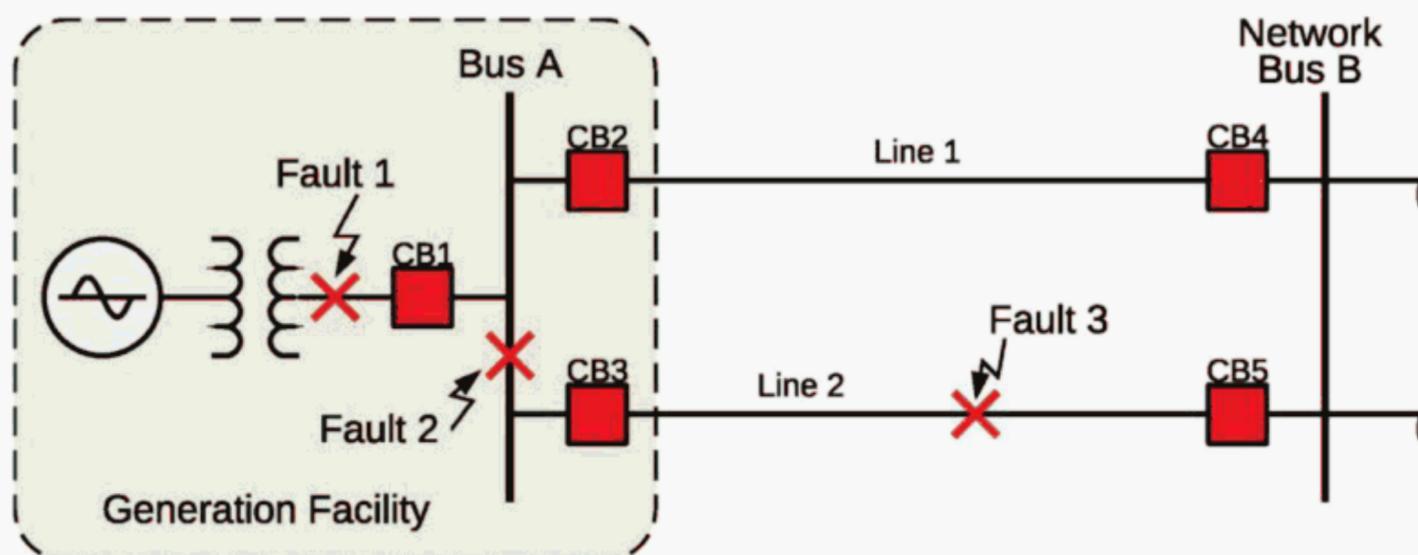


Figure 1—Example of tripping coordination for fault location

#### 4.2.2.1.5 Protection considerations for power system stability

System planning studies are performed as part of a generator interconnection assessment. These studies may discover that the interconnecting generator may become unstable and go out-of-step during certain contingencies. This condition is not desirable to either a generator owner or a transmission owner. Therefore, system planning engineers often specify high-speed clearing for the fault contingencies causing the unstable conditions. However, in some situations where high-speed protection either is not viable or does not mitigate the unstable condition, the transmission owner can advise the generator owner to install an out-of-step tripping scheme. In cases where the power swing is located in the transmission system, the transmission owner may install out-of-step detection, typically, in the form of an out-of-step blocking scheme, along with applicable communication scheme(s) to disconnect the generator(s) causing the unstable condition. It may be necessary to evaluate the interconnection for out-of-step tripping scheme application in the event of generator loss of synchronization and related protection scheme failure(s). Out-of-step protection schemes are not covered in this document; for detailed discussions, consult manufacturer literature and industry papers such as IEEE Std C37.102 and IEEE PES PSRCC Special Publication [B3].<sup>5,6</sup>

In extreme cases, a remedial action scheme (RAS) to disconnect generators may be required. Because misoperation or nonoperation of an RAS can pose serious risk to the system security, the RAS design must adhere to strict regional regulatory requirements.

#### 4.2.2.1.6 Autoreclosing practices

Autoreclosing is used to restore lines after momentary faults and can increase the reliability of and provide stability to the system. There are two types of autoreclosing:

- High-speed – typically occurs in 1 s or less. It may or may not be supervised by a phase fault detector; therefore, reclosing may be supervised by the type of fault, e.g., single line-to-ground fault.
- Time-delayed – typically greater than 5 s. This autoreclosing is supervised by line and bus voltages. A “dead line” is determined if the voltage is 20% to 30% of nominal. When the dead line is determined, the autoreclose occurs after the corresponding time delay.

If autoreclosing occurs while generation is still on the affected line, the resulting autoreclose would likely be out of phase and lead to generator and turbine damage. Due to this possibility, autoreclosing near generation facilities should be carefully evaluated. Typically, transmission lines that are adjacent to generation facilities are not automatically reclosed first from the generation terminals for personnel safety, equipment damage, and liability reasons. On tie lines to generation facilities, high-speed autoreclosing is generally not performed. Time-delayed autoreclosing with voltage supervision is possible to allow restoration of station service to the generation facility. This approach should be discussed with the generator owner. If autoreclosing is allowed, a breaker failure direct transfer trip (DTT) from the generator breaker should be used to block autoreclosing of the remote station.

Other important considerations when evaluating autoreclosing include restoring load and avoiding sustained outages.

#### 4.2.2.1.7 Synchronizing practices

Generators are typically connected to an energized system via a synchronizing scheme, which may be automatic or manual. Synchronizing schemes are used to minimize torques imposed on the generator and prime mover by allowing a close only if differences between phase angles, voltages, and frequencies across an open synchronizing breaker are within acceptable limits.

<sup>5</sup>Information on references can be found in [Clause 2](#).

<sup>6</sup>The numbers in brackets correspond to the numbers of the bibliography in [Annex A](#).

However, during black-start situations or restoration following a system separation, a reconnection may occur at a location remote from the generator. The generator synchronizing breaker may already be closed so that its synchronizing scheme cannot be used. The nearer the reconnection point is to the generator, the greater the possibility of damaging torques due to an out-of-phase closure. Thus, breakers at likely reconnection locations near generators should be supervised by a synchronism check relay. The settings of the synchronism check relay should be carefully evaluated to provide a closing window that is narrow enough to prevent damaging torques to nearby generators.

For a detailed discussion of synchronizing function, see 7.3.1.

#### 4.2.2.1.8 Complete relay one-line diagrams for point of interconnection

Figure 2, Figure 3, Figure 4, and Figure 5 show various transmission-to-generation interconnection configurations with typically required interconnection relays, which were discussed in 4.2.2.1.2 and 4.2.2.1.3.

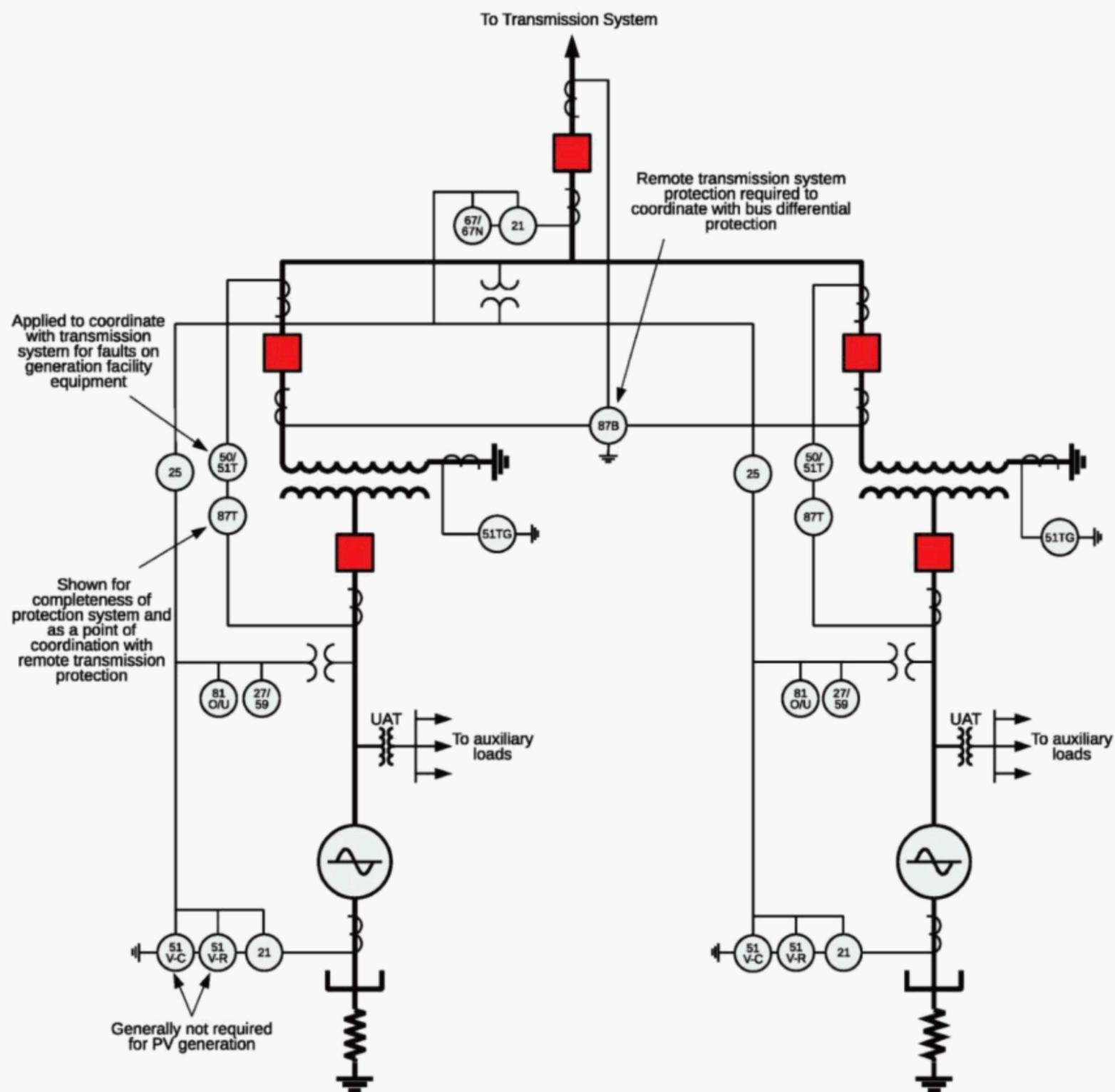


Figure 2—Typical interconnection relays for generation facility with multiple units

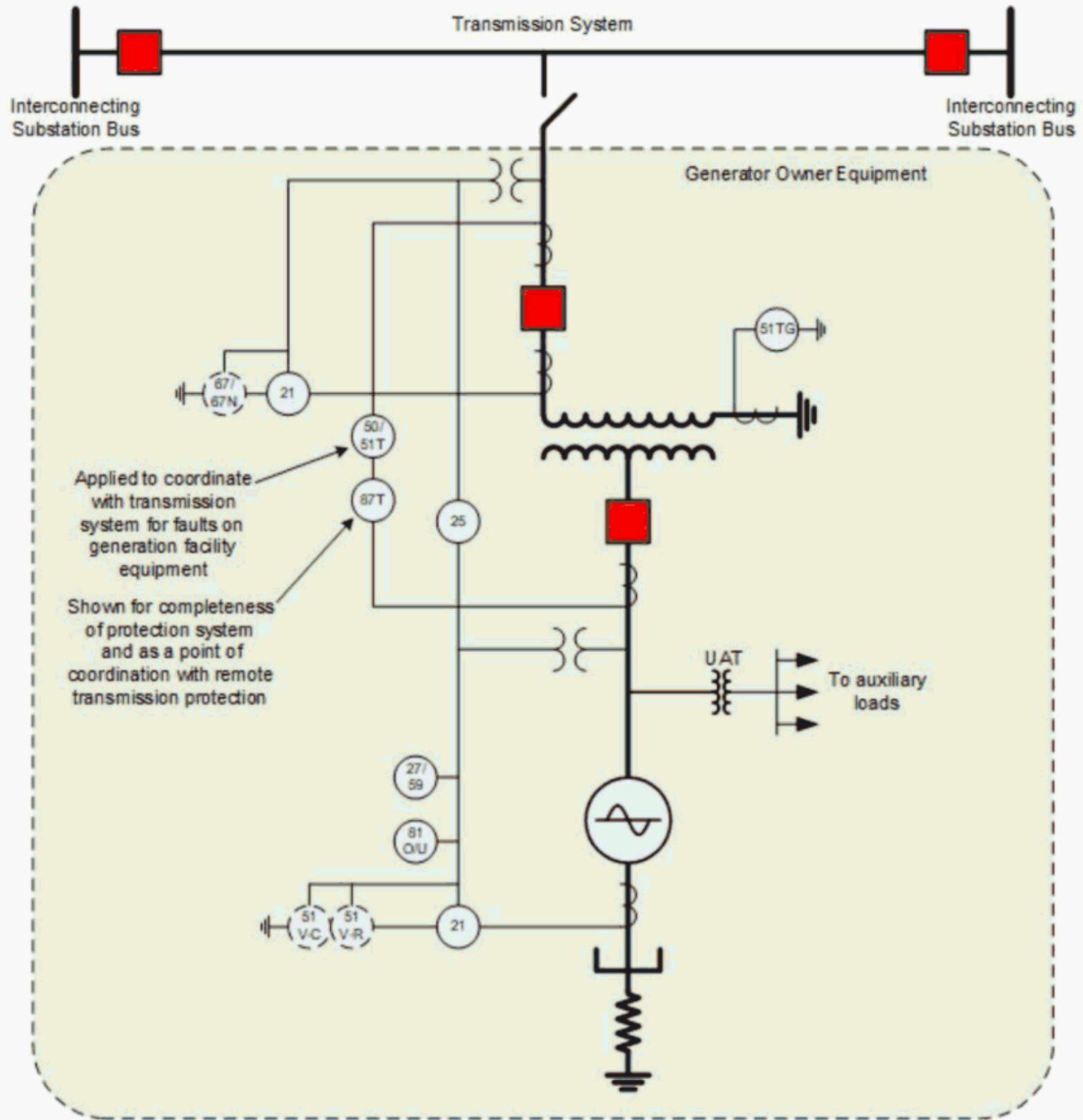


Figure 3—Typical interconnection relays for tapped generation

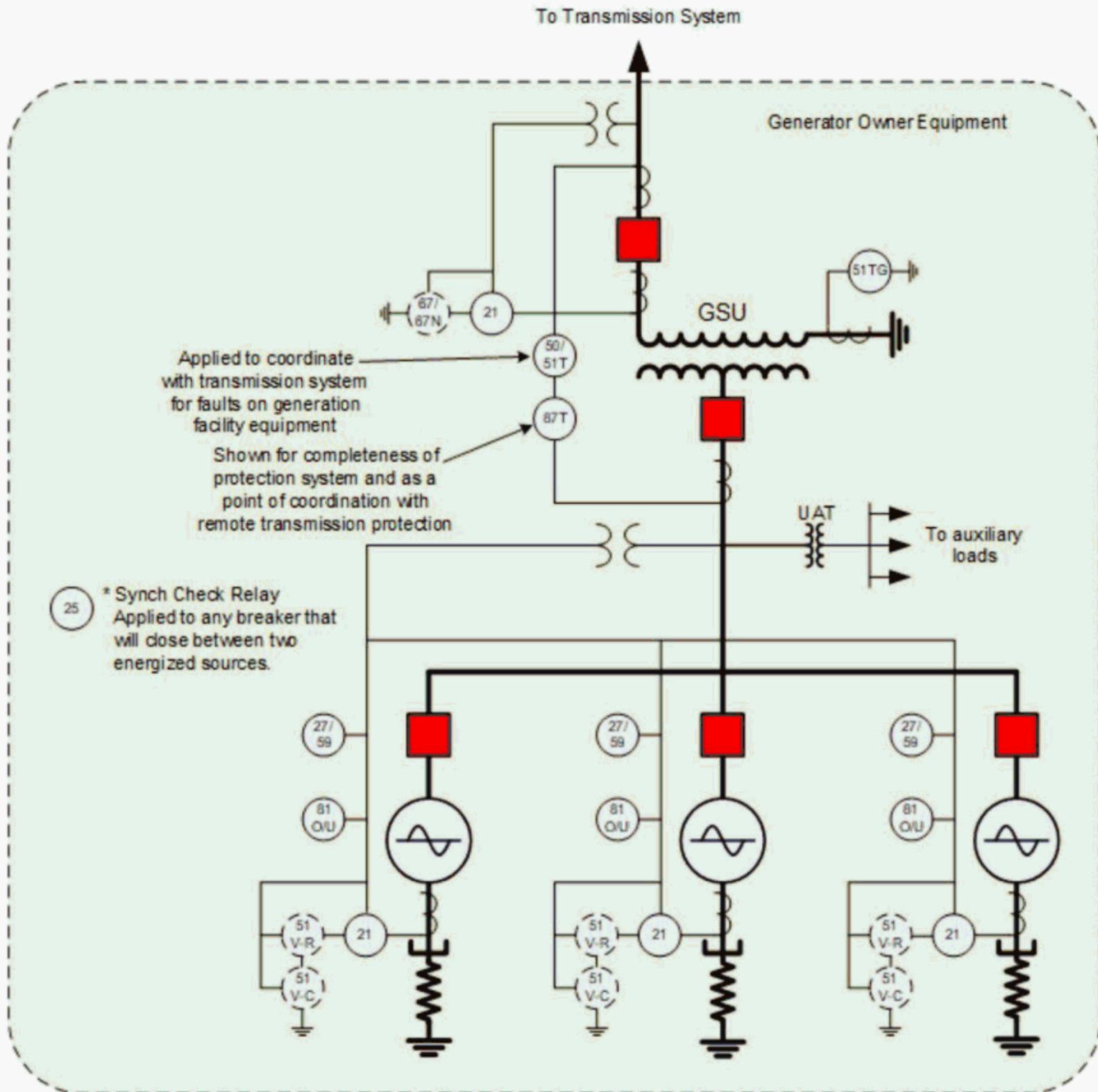


Figure 4—Typical interconnection relays for generation facility with multiple generators

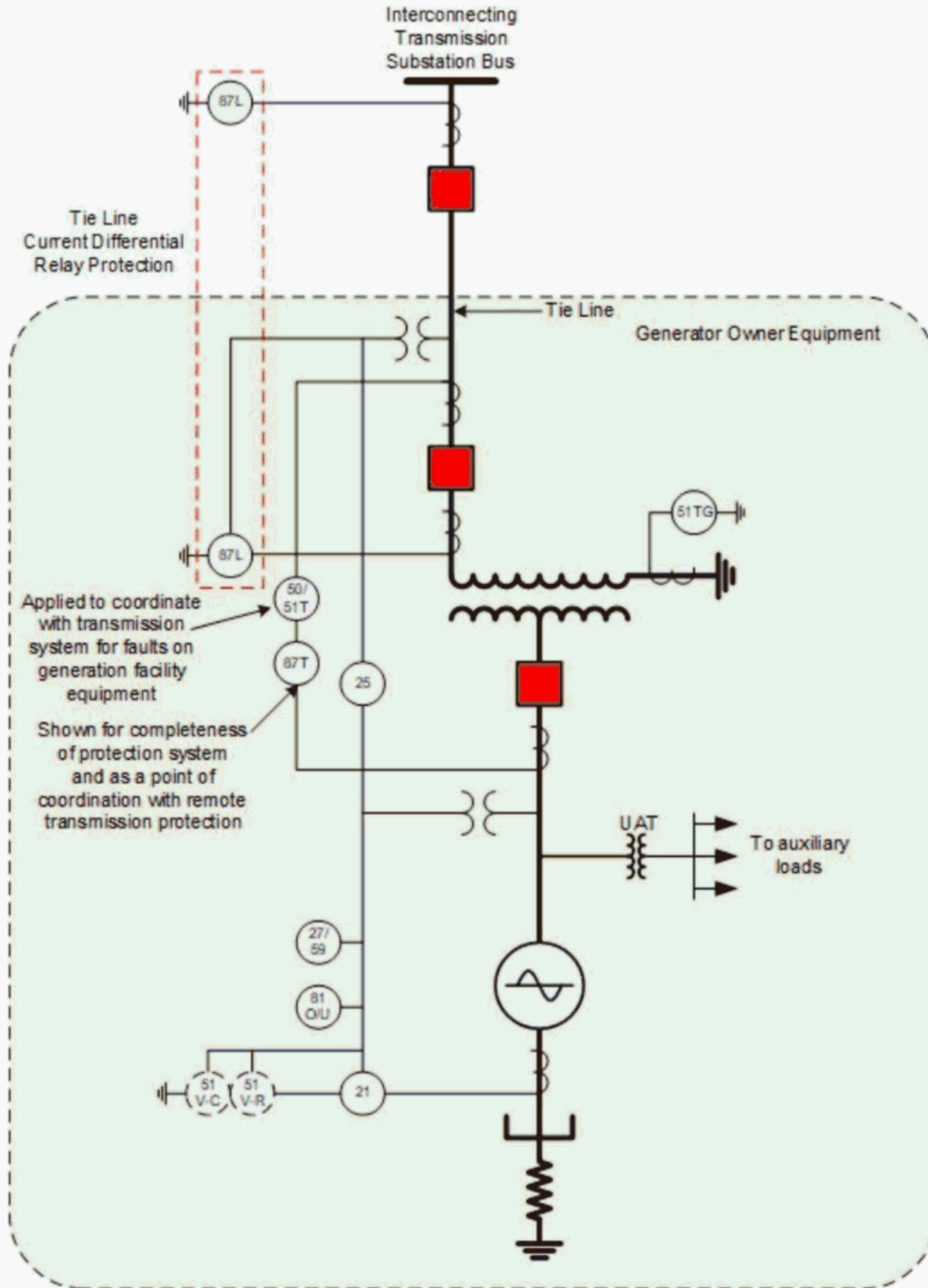


Figure 5—Typical interconnection relays for generation facility via tie line

#### 4.2.2.1.9 Transformer winding configurations

A transformer's winding configuration is important from the standpoint of detecting ground faults, providing a voltage reference on the transmission system, and filtering harmonics from the transmission system.

The different configurations are illustrated in [Figure 6](#).

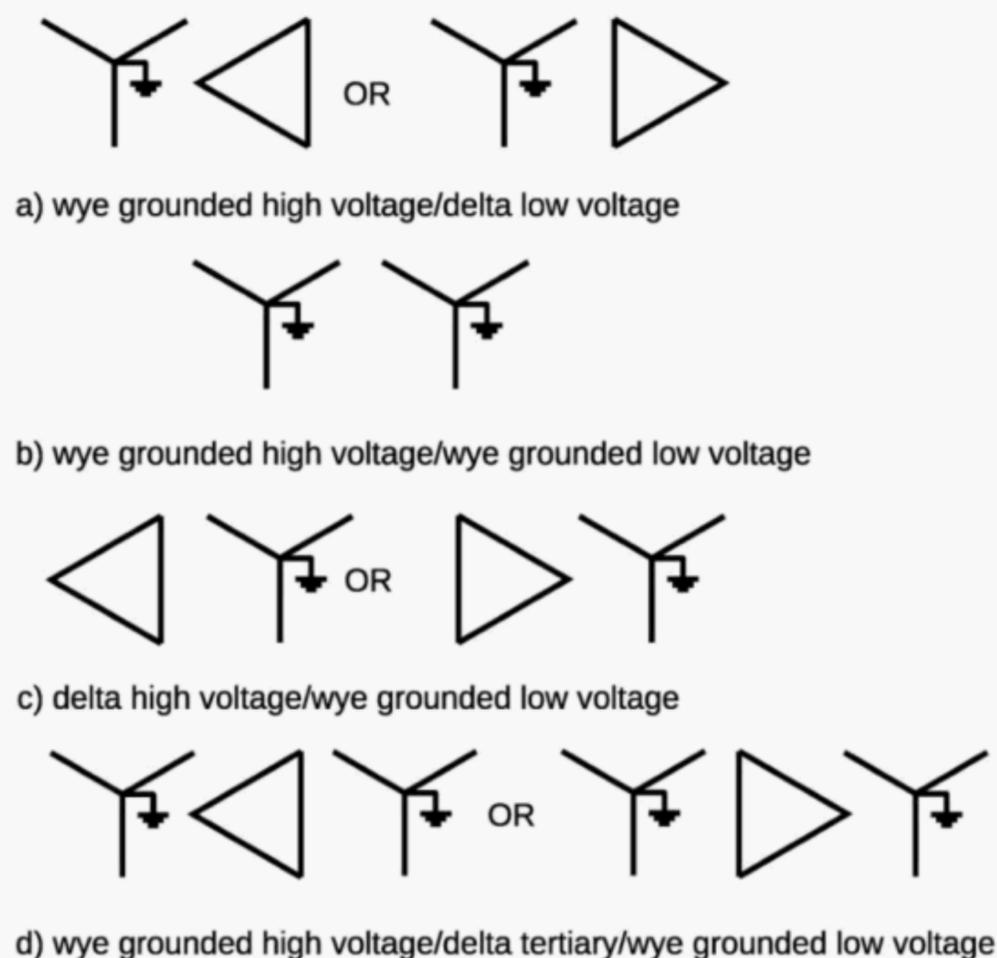


Figure 6—Transformer winding configurations

a) Wye-grounded high-voltage/delta low-voltage ([Figure 6a](#))

The wye connection on the high-voltage side provides a ground reference on the transmission system. The delta connection provides harmonic filtering and, in conjunction with the wye-grounded winding, acts as a zero sequence source to allow for ground detection relays to be used on the transmission system. The low-voltage delta winding does not provide a ground reference for the low-voltage side. If a ground reference is needed, a grounding transformer could be applied.

b) Wye-grounded high-voltage/wye-grounded low-voltage ([Figure 6b](#))

This configuration couples through any ground current source that exists on the two sides of the transformer. It does not provide harmonic filtering or the same level of zero sequence current for ground detection. Also, ground faults on the generator side of the interconnection are seen by the transmission line relaying unless certain measures are taken. For instance, if the transformer is tapped on the transmission line within the same station as the transmission line relays, then current transformers (CTs) from the high-voltage side of the transformer can be connected in parallel with the other line relay CTs. The CT polarities must be connected so that the line relays see faults only on the transmission system. In this case, faults that occur either in the transformer or on the low-voltage side of the transformer are not seen by the transmission line relays. On the other hand, if the transformer is tapped further down the line (not in the same station as the transmission line relays), then a communication channel-based blocking scheme would typically be needed.

c) Delta high-voltage/wye-grounded low-voltage ([Figure 6c](#))

This configuration provides harmonic filtering; however, delta connection does not provide a ground reference on the high-voltage side. As a result, the high-voltage phase-to-ground connected equipment could be subjected to overvoltages when the transmission breakers are opened and the generator is still connected as a source. A high-voltage grounding bank could be installed; however, this would be expensive. An alternative would be to implement a DTT to the generator breakers that is keyed from the transmission breakers, as discussed in [7.8.1.5](#).

d) Wye-grounded high-voltage/delta tertiary/wye-grounded low-voltage ([Figure 6d](#))

This configuration has the same characteristics as the wye/delta connection with the benefit of providing a ground reference and a ground current source for the low-voltage side. Additionally, it couples through any ground current source that exists on the two sides of the transformer, in a manner similar to the wye-grounded/wye-grounded configuration in [Figure 6b](#).

#### 4.2.2.2 Other information

##### 4.2.2.2.1 Grounding coordination

The generation facility's grounding should be coordinated with the grounding of the transmission system. In some instances, this might require a wye-grounded transformer connection on the transmission system's side of the GSU. In other instances, various transformer connections may be acceptable depending on the location of the generation facility if adequate protection is provided by the generator owner to detect a ground fault and limit any overvoltage to an acceptable level on the transmission system. Coordination of grounding between the generation facility and the transmission system is essential for developing an acceptable interconnection.

##### 4.2.2.2.2 Additional information requested by generator owner

In order to facilitate the design and installation of a transmission-to-generation interconnection, the generator owner may need to request information about the transmission system adjacent to the point of interconnection. The information may include the transmission line design, construction, and routing; interconnection substation location and general arrangement; general arrangement of the metering and meter data availability; data and monitoring requirements; and the transmission owner's grounding practice and lightning protection practices or requirements.

##### 4.2.2.2.3 System impact studies of the new facility

System studies are conducted to assess the effects of the proposed generation interconnection on the transmission system and the modifications required to allow the interconnection. These studies are conducted at several different analysis levels, depending on a number of factors. The studies increase in engineering detail, beginning with feasibility studies, system impact studies, and interconnection facility studies. The most detailed studies include system stability, critical clearing times, and breaker interrupting duty.

#### 4.2.3 Generator owner

##### 4.2.3.1 Protection information

###### 4.2.3.1.1 Point of interconnection

The preferred point of interconnection is proposed by the generator owner and is evaluated and agreed to by the transmission owner. It may take several iterations before a final location is agreed upon. The selected point of interconnection is essential from a protective relaying standpoint. The type of protection schemes required and the transmission fault data are dependent on the specified location in the transmission system.

A common point of interconnection is at a disconnect switch on the transmission side of the interconnecting breaker.

#### 4.2.3.1.2 Expected in-service date

During the course of the study process, a customer impact assessment is generally performed, and an expected date of commercial operation should be agreed upon. This in-service date is generally agreed upon during the study phase to build the generating facility and then updated as needed during the design/execution phase of the project.

#### 4.2.3.1.3 Drawings for review

Complete and up-to-date system drawings for the switchyard, generator, GSU, and collector bus electric systems of the generation facility are key components for the protection design. The drawings listed below contain information such as equipment ratings, bus configuration, protection schemes, metering locations, and system tie-in locations. These drawings are generally developed in the study phase for a new project and evolve as the plant design is finalized.

- Overall – one-line diagrams
- Relaying and metering – one-line diagram
- Three-line diagrams
- DC schematic diagrams
- Communication diagrams

For a more detailed discussion of schematic diagrams, see IEEE PES PSRCC WG I5 Technical Report [\[B6\]](#).

The transmission owner may require submittal of a site plan showing the property lines and the location of buildings and structures including the point of interconnection structure.

#### 4.2.3.1.4 Generation facility transformer data

Because of their critical nature to a generation plant, transformer protection considerations contribute to the overall project success. Transformer data is utilized for protection settings and also assists in developing phasing diagrams, system drawings, equipment sizing, and auxiliary power ratings. At a minimum, the transformer vendor should provide the following information:

- a) Base natural and forced cooling MVA ratings
- b) Transformer impedance, including positive- and zero-sequence, and X/R ratio
- c) Maximum fundamental inrush current
- d) Primary and secondary voltage
- e) Winding configuration
- f) Winding quantity
- g) Temperature rise
- h) Class (e.g., ONAN/ONAF)
- i) Liquid filled or dry type
- j) Load losses
- k) No-load losses
- l) Tap configuration
- m) Number of taps

- n) Phasing
- o) Damage curve
- p) V/Hz excitation curve

#### 4.2.3.1.5 Synchronous generator data

When considering generation-to-transmission interconnection protection practices, generator data is not only essential to the protection scheme but also required for several equipment sizing calculations, which include the GSU, auxiliary transformers, generator circuit breaker, and isolated phase bus duct. At a minimum, the generator vendor should provide the following information:

- a) Generator nominal voltage rating
- b) Generator base MVA rating
- c) Generator power factor
- d) Generator impedance (synchronous reactance, transient reactance, subtransient reactance, and negative sequence saturated reactance)
- e) Relaying and metering one-line diagram(s), including CT and voltage transformer (VT) locations, connections, ratios, and accuracy class
- f) Generator neutral grounding transformer ratio and grounding resistor
- g) Relay contact development
- h) Exciter data, including excitation system model diagram and parameters and power system stabilizer
- i) Machine limits
- j) Generator capability curve (D-Curve)
- k) Generator excitation curve
- l) Test reports
- m) Control system information
- n) Generator time constants and inertia constant

#### 4.2.3.1.6 Wind turbine generator (WTG) data

A WTG may be classified as one of five types:

- Type I WTG is a squirrel cage induction generator, which is connected to the wind plant collector system through a step-up transformer and a soft starter, and may have switched power factor correction capacitors.
- Type II WTG is a wound rotor induction generator with adjustable external rotor resistance controlled by power electronics to enable the machine to operate over a wider range of slips compared to a Type I induction machine. Power factor correction capacitors are also included.
- Type III WTG is a variable speed asynchronous wound rotor generator with a three-phase AC field supplied by the generated voltage through an AC-to-DC-to-AC converter, which provides operation over a wide range, both above and below synchronous speed.
- Type IV WTG is an AC generator with the stator windings connected to the power system through an AC-to-DC-to-AC converter.

- Type V WTG is a synchronous generator mechanically connected to the turbine blades through a variable ratio hydraulic torque converter, to drive the generator at power system frequency. Refer to 4.2.3.1.5 for generator data.

For more detailed information on modeling WTGs, see IEEE PES Joint Working Group Report [B9].

To summarize, the fault study data requirements from a WTG manufacturer depend on the type of WTG. All types require data from the manufacturer for the WTG type, rated voltage, current, MW, and synchronous reactance,  $X_d$ . Additionally, the following data is required depending on the type:

- Type I:  $X_{d'}$  or  $X_{d''}$
- Type II:  $R_r$  and  $X_{d'}$
- Type III:  $X_{d'}$  and  $I_{Smax}$
- Type IV:  $I_{max}$
- Type V:  $X_{d'}$ ,  $X_{d''}$

where

- $X_{d'}$  is generator transient reactance
- $X_{d''}$  is generator subtransient reactance
- $R_r$  is generator rotor resistance
- $I_{Smax}$  is generator maximum stator output current controlled by rotor converter
- $I_{max}$  is maximum rotor converter fault current

#### 4.2.3.1.7 Solar generator data

Photovoltaic (PV) inverters have similar characteristics as those for WTGs, with the exception that there is no prime mover with a rotating mass. The AC fault current from the inverters is primarily determined by the inverters' automatic controls. The resulting fault current contribution characteristics also vary depending on the inverter manufacturer but typically include a sub-cycle 2 to 5 per unit of maximum output magnitude. This is due to discharge of the inverter AC filtering components, which drops quickly to 1.1 to 1.2 per unit of available inverter maximum AC output via the inverter controls. The maximum current may also increase in order to meet low-voltage ride-through requirements, which in some cases could be 2.0 per unit of available maximum output for more than 5 cycles. This should be taken into account when setting instantaneous overcurrent elements.

The wide variability of inverter short-circuit current magnitude presents relay challenges in that faults on the transmission line cannot be reliably detected by the generation facility relays in order to trip and separate the PV facility from the transmission system. Often, a DTT is utilized to send a trip from the utility relays to the generating facility interconnection breaker to remove the generator as a source of fault current on the transmission system.

In some locations the inherent capability of the inverter to only operate with an AC source applied may be used to allow the inverter to trip once the transmission system breaker has tripped. The timeliness of the inverters to trip may be affected by other factors such as low-voltage ride-through requirements and local system conditions/configuration (e.g., other rotating machines on the line section), both of which could prevent the inverters from detecting a loss of AC and allowing them to stay online longer than intended.

Data required for a PV facility interconnection may be as follows:

- a) Total generating facility rated output (MW)
- b) Generating facility auxiliary load (MW)
- c) Project net capacity [a) – b) from above] (MW)
- d) Standby load when generating facility is offline (MW)
- e) Number of generating units
- f) Individual generator rated output (MW for each unit)
- g) Manufacturer
- h) Year manufactured
- i) Nominal terminal voltage (kV)
- j) Rated power factor (%)
- k) Type (DC with inverter)
- l) Phase (three phase or single phase)
- m) Connection (delta, grounded wye, ungrounded wye, impedance grounded)
- n) Generator voltage regulation range ( $\pm$  %)
- o) Generator power factor regulation range; number of inverters to be interconnected pursuant to the Interconnection Request
- p) Inverter manufacturer, model name, number, and version
- q) List of adjustable set points for the protective equipment or software
- r) Maximum design fault contribution current:
  - 1) Short time ( $X_{d'}^r$ )
  - 2)  $X_{d'}^r$  time duration
  - 3) Long time ( $X_d$ )
  - 4)  $X_d$  time duration
- s) Low-voltage ride-through capability
- t) Harmonics characteristics
- u) Startup requirements (i.e., speed of inverter online sequencing)
- v) Inverter characteristic data (sequence impedance data) for use in fault modeling studies and other transient analysis studies

#### 4.2.3.1.8 Collector system configuration and impedances for wind and solar power facilities

##### — Wind power facilities

Collector system design takes into account environment, terrain, soil conditions, grounding, economics, protection, operation, maintenance, and efficiency. Wind plants are typically connected to the power system through a collector substation, which aggregates the generation of multiple WTGs and steps up the generated voltage to the high-voltage or extra-high-voltage transmission system. The collector substation resembles a typical distribution substation, with high-voltage bus and breakers,

one or more transformers, low-voltage bus, and multiple collector feeders. Collector feeders are radial overhead or underground lines, typically 34.5 kV, that connect to multiple WTGs. A feeder may have multiple branches, depending on the terrain and location of individual WTGs. The feeder may also include a grounding transformer to provide a ground reference and limit overvoltages during ground faults. The collector substation may also include switched capacitor banks, reactors, or dynamic VAR controllers.

A typical WTG consists of a tower supporting a nacelle, which contains the turbine hub, transmission gears, generator, excitation system, generator protection, controls, and meteorological measurement system. The nacelle can be rotated through 360° to orient the turbine into the wind. The angle of the turbine blades, or sails, can be changed by the controls to keep the speed of the turbine relatively constant under varying wind velocities or completely feathered (the blades are turned so they are in parallel to the wind flow to eliminate torque) to shut down the turbine. A transformer is included, which may be either in the nacelle or at the base of the tower, to step up the generated voltage to the collector system voltage. Pad-mounted switchgear at the base connects the high-voltage terminals of the step-up transformer to the collector feeder and provides protection for the step-up transformer, typically in the form of switch-fuse units.

— Solar power facilities

Solar field installations have DC and AC components. The DC component is made up of the solar panels configured in a parallel series configuration referred to as an “array” in order to meet the given DC voltage and capacity for the selected inverter. The AC fault current from the inverters is primarily determined by the inverters’ automatic controls. The AC outputs of the inverters are stepped up to a distribution voltage (34.5 kV, for example) and are paralleled together on feeders similar to a WTG configuration. The feeders are then terminated to the main step-up transformer, which is interconnected to the transmission system.

Information required for the station feeder would be as follows:

- a) Nominal voltage
- b) Maximum anticipated line loading (A)
- c) Positive sequence resistance (R1) for entire line length of each collector circuit (per unit)
- d) Positive sequence reactance (X1) for entire line length of each collector circuit (per unit)
- e) Zero sequence resistance (R0) for entire line length of each collector circuit (per unit)
- f) Zero sequence reactance (X0) for entire line length of each collector circuit (per unit)
- g) Line charging current (expressed as B/2) for entire line length of each collector circuit (per unit)
- h) Protective relay types and proposed settings

During the project design phase, the protection philosophy is established and protective relays are procured that allow for the implementation of the protection scheme. For the relays that are required to provide the protective functions critical to the transmission system, their manufacturer, type, model, and catalog number should be specified to generation facility designers. The protection engineer then develops the relay settings for each protection relay and performs the relay coordination study.

#### 4.2.3.1.9 Appropriate protection and control schematic drawings

Project relaying and metering one-line diagrams and control schematics are developed during the project design phase. Once these drawings are complete, the engineer utilizes them as a reference for the protection scheme.

#### 4.2.3.2 Other information

##### 4.2.3.2.1 Voltage ride-through capability

Generating stations should be able to operate through periods of voltage excursions as specified by a transmission owner's system operating limits and applicable regulatory requirements to help ensure that a generator owner sets generator protective relays so that generating units remain connected.

For low-voltage ride-through, the generation facility is to remain connected for a transmission system fault that is not on the point of interconnection. The generation must remain synchronized, and the critical auxiliary functions must not disconnect during the voltage decline due to the fault for normal fault detection and clearing. If, for a fault on the transmission system, the voltage drop causes the generation to disconnect, the loss of generation reduces the voltage even further. This may prolong and exacerbate the voltage dip and cause additional generators to trip offline; that event could lead to a cascading outage. The requirement to achieve low-voltage ride-through should be carefully addressed and implemented in the protection design.

##### 4.2.3.2.2 Generator voltage, reactive power, and/or power factor control

Generator capability data is required to set any functions associated with abnormal conditions. In some designs, a clutch is utilized to disengage the turbine shaft to operate the generator as a synchronous condenser. The synchronous condenser either absorbs or generates reactive power to adjust grid voltage or improve power factor. A generator capability curve helps to evaluate maximum leading and lagging conditions. This directly affects the reverse power (32) function as two different pickup set points need to be established based on the motoring power in normal and condenser mode.

##### 4.2.3.2.3 Frequency limits

Frequency limits for generator protection can be established as a backup to the turbine control system for the generator. Regulatory entities call for coordinated off-nominal frequency plans that utilize time delays to keep generators online during system disturbances.

##### 4.2.3.2.4 Short-circuit current levels

A generator owner typically receives from a transmission owner the maximum and minimum short-circuit current levels without the new generation contribution. The generator owner then evaluates the received data combined with the proposed generation.

##### 4.2.3.2.5 Auxiliary power requirements

Whether plant auxiliary loads are supplied from the generator leads (via a unit auxiliary transformer) or from a separate system auxiliary transformer, the transmission owner needs to know the characteristics of the maximum load of the auxiliary power system, especially when the generation is starting up since that load is supplied from the transmission system. This normally consists of the total load of running fans, pumps, lights, HVAC, etc., plus the locked rotor current and accelerating time of the largest motor.

#### 4.3 Specific considerations

In determining the final interconnection, consideration should be given to the design of the interconnection, the arrangement of the transmission system, its protective relaying requirements, and other factors.

##### 4.3.1 Ownership demarcation

Individual operating and maintenance philosophies of the generator and transmission owners may impact electric system design. Regardless of ownership, however, the protective equipment should be specified and designed to provide a coordinated system. Proper engineering design must not be compromised, but



the protection of the interconnection facilities should satisfy the objectives of both parties. In all cases, the protection requirements, equipment specifications, relay settings, station battery requirements, and testing procedures should be discussed and agreed upon by both parties.

#### 4.3.2 Long-term outages

Long-term outages result from equipment failures that require an extended time to repair or replace. If an interconnection consists of a single line supplied from a single source connected to a single transformer, it is subject to long-term interruptions due to forced or planned outages of the supply source, line, or transformer. To reduce the possibility of long-term outages, two or more lines may be considered.

#### 4.3.3 Momentary outages

Momentary outages are generally caused by a trip of the transmission line to the generation facility that is quickly returned to service by a successful autoreclosing of the line. Upon separation from the transmission system, the generating unit likely shuts down, even with successful line restoration by autoreclosing.

#### 4.3.4 Degraded grid voltage schemes and set points

Voltage sags are caused by faults on the transmission system and may or may not cause an outage to the generator. However, the fault location, type of fault, system configuration, and loads influence the magnitude of these voltage sags. Conversely, voltage swells may also occur on the unfaulted phases of a three-phase system. Voltage transients may also be caused by switching operations during nonfault conditions. Extended voltage sags may occur as a result of loading or cascading outages on the transmission system.

The voltage sags experienced by the generator would depend on the winding connection of the GSU. Some generator auxiliary systems are sensitive to these fluctuations in voltage, and degraded grid voltage schemes were developed to separate the generating facility from the transmission system. This enables backup auxiliary power sources that are of the proper voltage to maintain critical systems. For example, nuclear plants' auxiliary systems are especially sensitive to degraded voltages.

The set points for these schemes are derived based on the needs of the systems involved. These settings must be coordinated between the generation facility and transmission system.

#### 4.3.5 Under/overfrequency schemes and set points

A mismatch between load and generation or disturbances typically causes fluctuations in system frequency. These fluctuations in frequency can have detrimental effects on both transmission system customers and generating units. It is important to address these fluctuations.

Under/overfrequency schemes are employed to respond to the frequency fluctuations or to separate frequency sensitive systems. They may be owned by the generator owner, transmission owner, or both.

These protective functions can be used to minimize the equipment damage at facilities that, through the isolation of transmission system faults, have become islanded with the generation.

The set points for these schemes are derived based on the needs of the systems involved. These settings must be coordinated between the generation facility and transmission system.



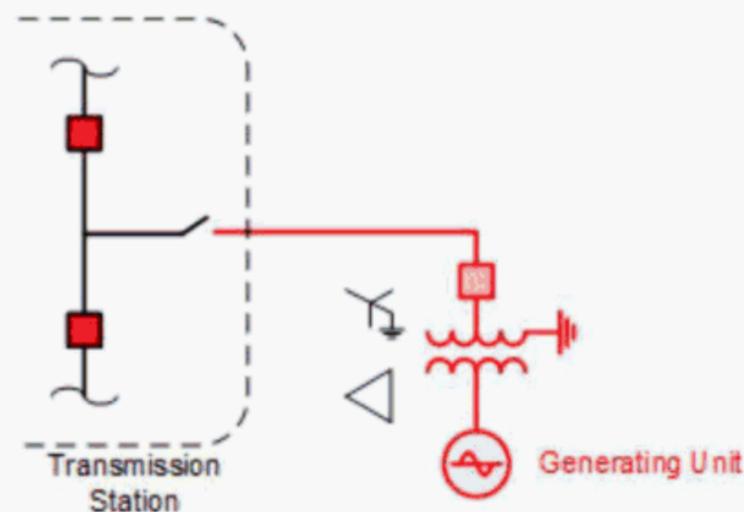
## 5. Typical transmission-to-generation interconnection configurations

### 5.1 Interconnection configurations

A generation facility can be interconnected with the transmission system using one of the three interconnection configurations as shown in [Figures 7-12](#).<sup>7</sup>

- Tie line from the generation facility to the existing transmission substation bus ([Figure 7](#) or [Figure 8](#))
- New switching station sectionalizing an existing line into two separate circuits ([Figure 9](#) or [Figure 12](#))
- Tapped connection to an existing transmission line ([Figure 10](#) or [Figure 11](#))

The interconnection configuration with a tie line can be used to connect a generation facility to the transmission owner's substation. At the transmission substation, the line position can be either a double ([Figure 7](#)) or a single ([Figure 8](#)) breaker arrangement. The additional breaker in the double breaker arrangement allows one breaker to be taken out of service for maintenance without requiring an outage to the generation facility. In either case, an interconnection is easily achievable using a two-terminal line protection scheme. However, the cost of a long transmission circuit and unavailability of the right of way are often obstacles when the existing switching station is not in proximity to a generation facility. Further, a spare line position or space to create a new line position has to be available in the existing transmission station to interconnect a new circuit from the generation facility.



NOTE 1—High-voltage winding of GSU may be delta in some cases.

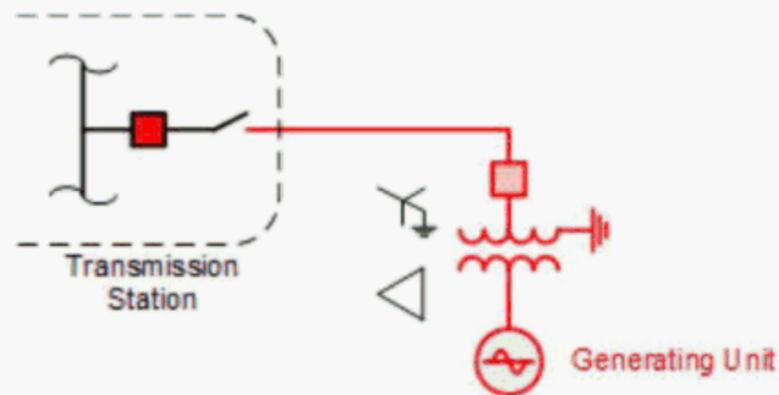
NOTE 2—The GSU high-voltage side breaker may or may not be installed depending on a transmission owner's requirements.

Figure 7—Tie line

An interconnection via a new switching station ([Figure 9](#)) is the most desirable configuration for transmission owners because it has relatively low impact on the configuration of existing stations and the protection systems typically involve two-terminal protection schemes. A ring bus or breaker-and-a-half configuration provides flexibility because it permits taking any of the breakers out of service for maintenance without interruption to the generation facility. Furthermore, ring bus, breaker-and-a-half, or similar configurations such as three-breaker straight bus minimize disruptions to the transmission system for a fault in the generation facility. The new switching station, property acquisition, and issues associated with land development may affect the desired bus configuration. Though land availability or purchases may not be in the purview of protection engineers, the outcome of those decisions may impact protection designs.

<sup>7</sup>Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement the standard.

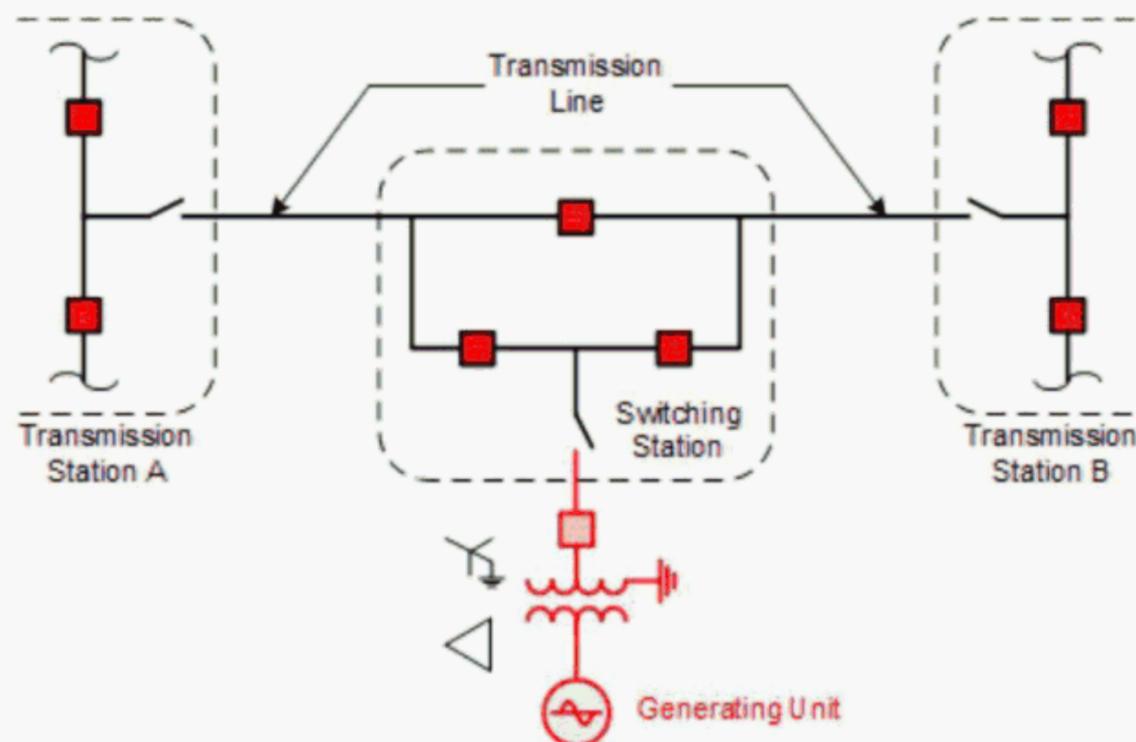




NOTE 1—High-voltage winding of GSU may be delta in some cases.

NOTE2—TheGSUhigh-voltagesidebreakermayormaynotbeinstalleddependingonatransmissionowner'srequirements.

Figure 8—Single breaker arrangement



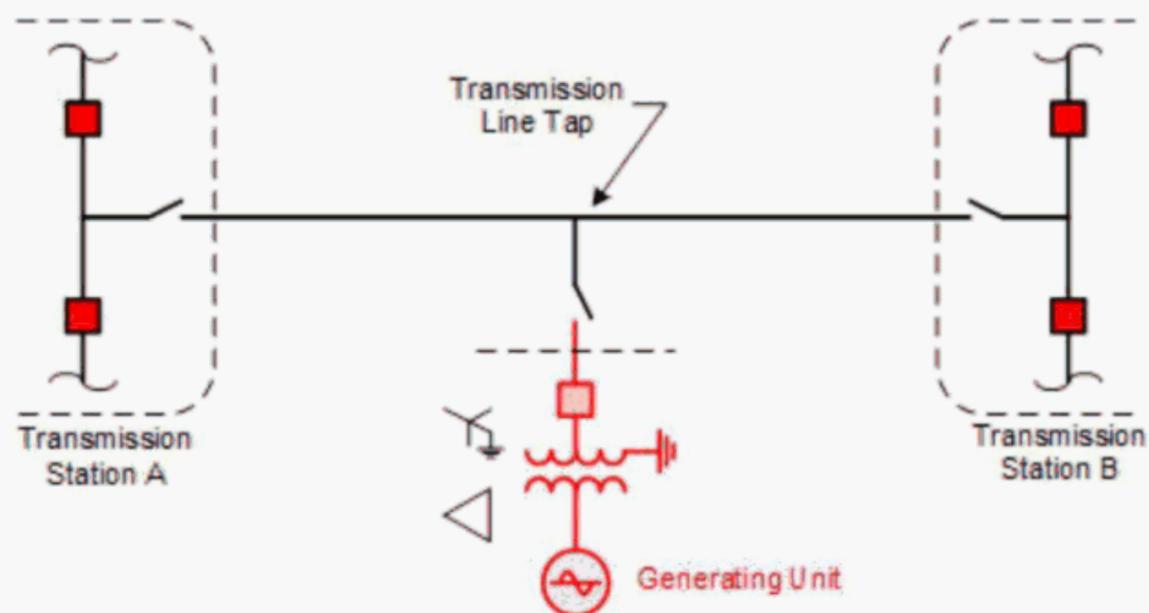
NOTE 1—Transmission station's bus is shown in dual breaker configuration. A single breaker or other arrangement could be present instead.

NOTE 2—High-voltage winding of GSU may be delta in some cases.

NOTE3—TheGSUhigh-voltagesidebreakermayormaynotbeinstalleddependingonatransmissionowner'srequirements.

Figure 9—Switching station

While the tapped connection ([Figure 10](#)) may be the most economical based on its initial cost, this configuration may contribute to operational problems for both the transmission system and the generation facility. The reliability of the transmission circuit to which the generation facility is connected is reduced. With the tapped connection, the line protection is typically more complex and, often, requires a communication-assisted protection scheme. Reliability may be decreased as the line protection becomes more complex by adding more protective elements. The details on protection challenges associated with the tapped connection are discussed in [7.8.1](#).



NOTE 1—Transmission station's bus is shown in dual breaker configuration. A single breaker or other arrangement could be present instead.

NOTE 2—High-voltage winding of GSU may be delta in some cases.

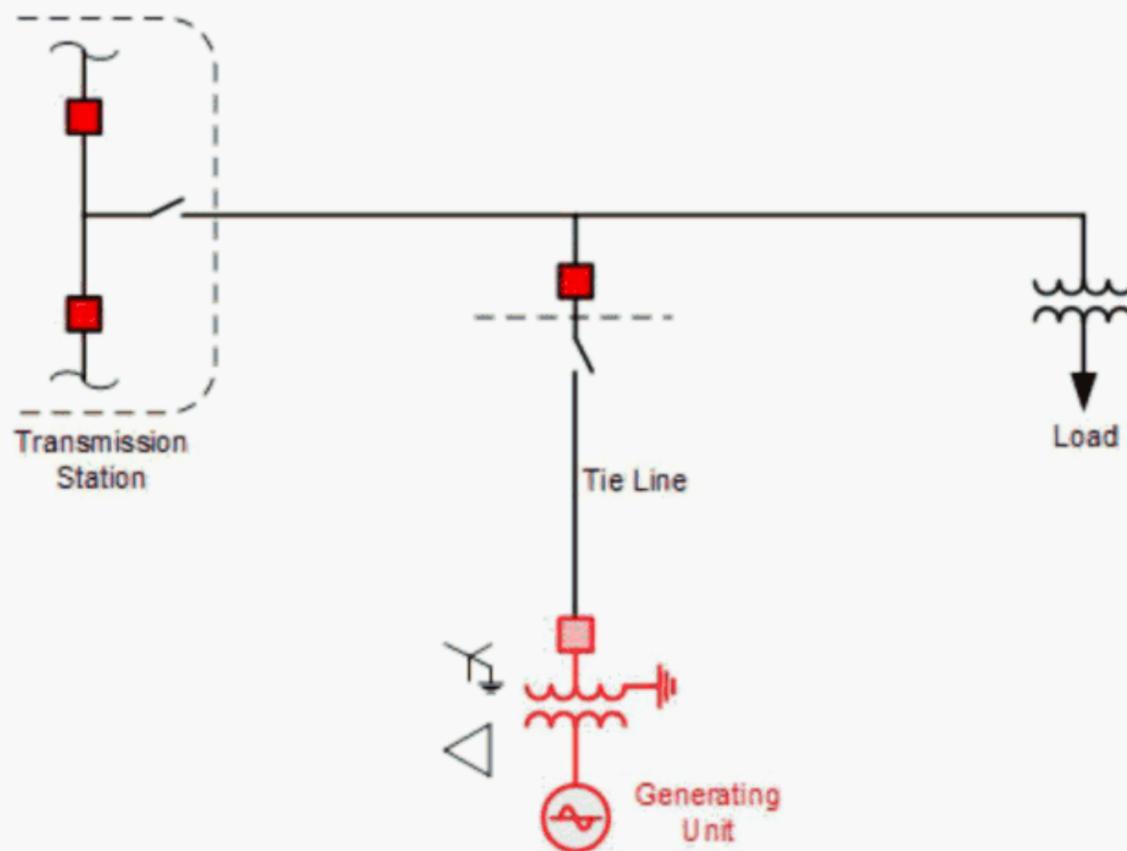
NOTE 3—The GSU high-voltage side breaker may or may not be installed depending on a transmission owner's requirements.

Figure 10—Tapped connection

The new line tap adds to the exposure for line faults that cause interruptions to the existing circuit if a breaker is not installed at the point of interconnection to isolate the faults on the new tap from the main circuit. The initial cost of this type of generation interconnection is lower for the generation interconnection customer, but the long-term cost of loss to generation production due to the loss of the transmission line may affect the economics of the plant.

With the ring bus configuration for a transmission-to-generation interconnection, as shown in [Figure 9](#), both transmission lines connecting the substation at the point of interconnection to the transmission system would have to be lost concurrently before the interconnection of the generation facility to the transmission system would be lost. The likelihood of this happening is very low so the reliability of the interconnection is greater with the ring bus configuration than with the tapped connection shown in [Figure 10](#). For tapped connections, although the duration of the outages of the transmission-to-generation interconnection may not be long for temporary faults, the loss of production at the generation facility may be significant depending on its type because the momentary loss of transmission could result in many hours or days of loss of generation production.

[Figure 11](#) represents a transmission configuration where the generation taps into a line also serving load. A fault on the tie line is cleared by the single breaker at the interconnection substation; that breaker also isolates the generator. The transmission load is still served uninterrupted from the transmission station. A fault anywhere on the main line will be cleared by both the transmission station breakers and the breaker at the tap point; as a result, both the generation and the load will be lost. It should be noted that a loss of the transmission source causes the generation and transmission load to form an unintended island, which may require additional protection.



NOTE 1—Transmission station's bus is shown in dual breaker configuration. A single breaker or other arrangement could be present instead.

NOTE 2—High-voltage winding of GSU may be delta in some cases.

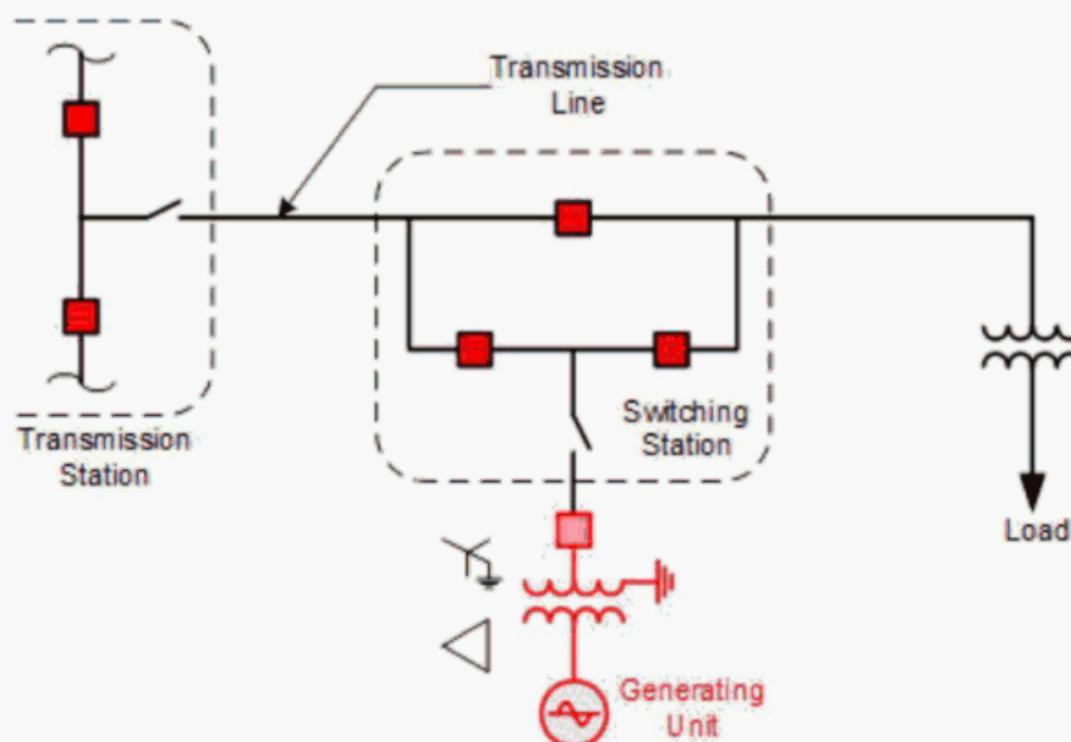
NOTE 3—The GSU high-voltage side breaker may or may not be installed depending on a transmission owner's requirements.

Figure 11—Tapped connection via tie line with radial transmission line to distribution load

Consider with caution the application of a switching station configuration that sectionalizes an existing line into two separate segments. As an example, a ring bus switching station configuration is shown in [Figure 12](#). A fault and loss of the line between the transmission station and switching station results in leaving the generation isolated with the remaining load on the other line. If the generation facility does not have the power capability to carry the load or is not designed to operate as an island, the power quality to the load isolated with the generation would be compromised. Therefore, all of the ring bus breakers at the point of interconnection should trip for the fault described above.

Besides this operational problem, the addition of future generation on the transmission line feeding the load may require a DTT from the transmission substation and from the ring bus switching station at the point of interconnection to trip the added generator for faults on the line between the transmission system and the point of interconnection and for faults on the line feeding the load. This adds to the cost, maintenance, and operational complexity of the system and should be taken into consideration.

The installation of the ring bus typically increases reliability for the interconnection since the ring bus divides the line into two portions and a subsequent fault on the transmission line feeding the load does not result in an outage to the generator. The amount of reliability increase depends on the relative lengths of the lines. For example, a short length of the line between the transmission system and the point of interconnection would provide more benefit due to a lower line fault exposure than a longer line length that may result in a greater fault exposure to the generator. Each of the above issues should be taken into account when deciding if a ring bus as shown in [Figure 12](#) is installed.



NOTE 1—Transmission station's bus is shown in dual breaker configuration. A single breaker or other arrangement could be present instead.

NOTE 2—High-voltage winding of GSU may be delta in some cases.

NOTE 3—The GSU high-voltage side breaker may or may not be installed depending on a transmission owner's requirements.

Figure 12—Switching station in radial configuration with distribution load

## 5.2 Ground grid configuration

When the generating station ground grid is designed, careful consideration is taken to accommodate the total 3I0 fault current contribution. When a fault occurs at the high side of the generator step-up transformer, the fault is fed from local sources like the generator and remote sources. The local contributions from the generator circulate through the transformer neutral and the fault location and create a circulating current. The remaining remote fault current returns to its source through the ground grid and overhead lines. A split factor can be calculated to determine what fault current returns back on the overhead lines if remote substation data is available. During the worst-case ground fault, this circulating current phenomenon is important to note as design requirements should distinguish when the ground grid should withstand the total fault current contributions or only local fault current contributions since local fault current contributions do not create significant earth potentials. If the generating station ground grid needs to withstand the entire 3I0 fault current contributions (local and remote), it may be tied into the ground grid of the local substation. An isolated ground grid in the generating station should be required to withstand only the remote fault current contributions. Refer to IEEE Std 80 [B11] for more details on the ground grid design and 7.3.7 for more details on how the ground grid design can affect protection.

## 6. System studies

For transmission-to-generation interconnections, system impact and facilities studies are usually performed.

The system impact study generally includes an assessment of the impacts of the proposed generation interconnection, determination of adequacy of the transmission system to accommodate the requested service,<sup>8</sup> and identification of required upgrades to the transmission system.

The facilities study provides a more detailed estimate of the time and cost of implementing the necessary changes to the transmission system in order to provide the required transmission service.

A potential tool for performing power flow studies would be one of the commercially available power system simulation/analysis programs.

The studies specific to protection are presented in 6.1 through 6.5.

### 6.1 AC power flow analysis

An AC power or load flow analysis provides line flows and bus voltages across the transmission system during normal operation, single-contingency, or multiple-contingency scenarios. The introduction of new generation generally alters the line flows and bus voltages and may require upgrading of the existing transmission system (components such as circuit breakers and disconnect switches). Power flow impacts on protection devices can then be identified.

The study may include peak and light load, seasonal, or selected load scenarios. The types of contingencies to be studied are specified by the planning authorities.

For this study, a power flow model of the transmission system is needed.

### 6.2 Transient stability analysis

A stability study evaluates whether the interconnection causes angular or voltage stability problems during specified faults. If instability occurs, the critical clearing time of related protection devices can be identified by gradually reducing the protection clearing time and iteratively running the studies until the system gains stability. Scenarios under single and multiple contingencies need to be studied.

This type of study may identify the need for high-speed protection schemes on transmission lines in the study's area, out-of-step protection on new generators or interconnecting transmission lines, or out-of-step blocking on transmission protection.

Similar to the AC power flow analysis, this study may include peak and light load, seasonal, or selected load scenarios. The types of contingencies to be studied are specified by the planning authorities.

For this study, in addition to the power flow model, the data for generator, excitation system, governor system, and power system stabilizer is also required.

### 6.3 Short-circuit analysis

A short-circuit study determines the fault current level during specified short circuits. The results of this type of study are used to identify required electrical equipment upgrades as well as protective relay replacements and/or setting revisions.

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<sup>8</sup>Adequacy of the transmission system may extend beyond physical limitations into contractual limitations.

The short-circuit study requires the positive-, negative- and zero-sequence data of the transmission system and the sequence impedance of the generators for the subtransient and transient timeframes.

#### 6.4 Relay coordination studies

A relay coordination study is necessary to verify the performance of the protection system. This study is used to achieve proper fault identification and fault clearing sequence by the relays for their respective zones of protection.

This study requires the short-circuit model of the transmission system and a relay model database where the relay settings including CT and VT ratios are typically stored. One-line and DC schematic diagrams are also needed for this study.

#### 6.5 Subsynchronous resonance (SSR)

The portfolios of energy providers increasingly comprise renewable energy, including solar and wind generation. The sizes of individual facilities are also increasing as compared with the capacity of the transmission systems used to connect them to the load centers. As conventional power plants are retired, renewable energy sources become an increasing percentage of the overall energy portfolio. The effect of this change on SSR will likely become an even more important technical issue in the future.

Series capacitor compensation in transmission systems is an economical means to increase load-carrying capability, control load sharing among parallel lines, and enhance transient stability. However, capacitors in series with transmission lines may cause SSR that can lead to turbine-generator shaft failures and electrical instability. SSR is an electric power system condition where the power system exchanges energy with a turbine generator at one or more natural frequencies of the combined system below the synchronous frequency of that system (Anderson et al. [B1]).

The effects of SSR need to be analyzed and fully understood when planning an expansion or modification of a power system, including an addition of series capacitor compensation. The main concern with SSR is the possibility of generator shaft damage from torsional stresses caused by the long-term cumulative effects of low-amplitude torsional oscillations or the short-term effects of high-amplitude torques. Protective devices with capabilities of detecting SSR need to be installed where they can take corrective actions and modify the topology of the power system with the intention of eliminating SSR.

Sufficient studies should be performed to identify locations that are susceptible to isolation of generation or power electronic equipment with series compensated transmission lines and all possible contingencies and locations that could lead to SSR.

### 7. Protection system settings considerations

#### 7.1 General

All generation interconnections to the transmission systems should be designed to minimize safety hazards and adverse effects to the quality of the electric transmission service to other customers. Protective equipment may need to be added to a transmission owner's facilities to provide adequate protection of the transmission system in the vicinity of a generation interconnection. Requirements for additional protective equipment vary depending on the amount of generating capacity being added and on the nature of the local transmission system.

As part of the protection system, the generator owner is responsible for protecting the generation facility from faults occurring in the facility or on the transmission system.

## 7.2 Interconnection relay specifications

### 7.2.1 General considerations

The generator owner should design the protection systems and install, set, and maintain all protective devices necessary to protect the generation facility in accordance with ANSI/IEEE standards, applicable reliability standards, the interconnection system impact and facilities studies, and other applicable standards and guides. Protective devices, including those performing the protective functions required by the transmission owner, should be installed by the generator owner to disconnect the generation facility from the transmission system whenever a fault, abnormal operating condition, or equipment failure occurs. The generator owner should verify that such protective devices and related equipment properly coordinate with the transmission owner's protective equipment, both locally and remotely, and provide a comparable level of protection to the generation facility as is provided by the transmission owner for the interconnection facilities and transmission system. The specific requirements and specific protective devices to be installed may be determined as part of the interconnection studies.

The generator owner may be required to allow the transmission owner to review the generation facility protection and control design and settings coordination with the transmission owner's protective devices prior to and after the date of commercial operation. The transmission owner may reserve the right to refuse to allow the generator owner to initiate the tender of energy to the transmission system if, in the judgment of the transmission owner, the generation facility's protective devices, controls, or overall protection methods do not adequately restrain the generation facility from introducing or causing adverse impacts on the transmission system.

### 7.2.2 Utility grade relays

Protective relays utilized at the interconnection should

- Meet or exceed ANSI/IEEE standards for protective relays (i.e., IEEE Std C37.90, IEEE Std C37.90.1 [B12], IEEE Std C37.90.2 [B13], and IEEE Std C37.90.3 [B14]).
- Have the appropriate documentation covering application, testing, maintenance, and service.
- Give positive indication of what has caused a trip (targets).
- Have a means of testing that does not require disturbance to wiring (e.g., a draw-out case, test-blocks, test switches).

## 7.3 Protective functions

### 7.3.1 Synchronism check function (25)

For generation sources that can produce power without being tied to the transmission system, the generator owner typically synchronizes the generating facility to the transmission system across the breaker owned by the generator owner. The generator owner should provide a synchronism check control system to supervise the automatic, semiautomatic, or manual synchronization of the generation facility to the transmission system. Automatic synchronism check relays generally contain the manufacturer's optional voltage monitoring functions and supervise the closing of the circuit breaker. The transmission owner may provide a supervising relay for synchronism check of the generator's synchronizing relay.

The synchronism check control system should be designed to provide synchronizing limits for the breaker closing angle, voltage matching across the breaker, and frequency difference (or slip frequency).

The closing of the circuit breaker should ideally take place when the generating unit and the grid are at 0° phase angle with respect to each other. In order to achieve this, the breaker close command should be in

advance of an approaching phase angle coincidence between the generator and transmission system voltages to compensate for the breaker closing time.

The voltages across the breaker should typically be within 0% to 5% of nominal to allow synchronization. This limit aids in maintaining system stability by ensuring some VAR flow into the system.

Frequency difference should be minimized to the practical control/response limitations of the given prime mover. A large frequency difference may cause excessive accelerating or decelerating torques on the shaft of the machine.

As stated in [4.2.2.1.7](#), black-start or system restoration procedures may present situations where a reconnection occurs at a location remote from the generator so that the generator synchronism check relay cannot be used. Extensive studies are done by the transmission owner in advance to identify these possible reconnection points so that synchronism check relays can be installed if necessary. If the locations are close enough to existing and proposed generation so that an out-of-step closure could subject the generators to damaging torques, the settings of the synchronism check relays should provide an allowable closing window similar to that of the synchronism check relay at the interconnection.

### 7.3.2 Degraded grid voltage protection (27/59)

The magnitude and the frequency of the voltage at any location on a power system is an indication of the condition of that power system. This subclause does not address frequency, which is addressed in [7.3.6](#).

#### 7.3.2.1 Voltage magnitude

If the magnitude of the voltage is above or below the nominal value, it is an indication that there is either an excess or deficiency in the supply and consumption of reactive power. The magnitude of the voltage being out of tolerance can be an indication of a localized problem or of a systemwide condition. If critical transmission links have opened, the generation facility may end up in an island with a significant power balance issue.

The magnitude of voltage is critical to the operation of customers' loads. In many cases, the interconnected consumers in the area of the generation interconnection are transmission customers. Therefore, it is important for the transmission owner to maintain voltage within specified limits to minimize transmission equipment damage from an overvoltage or undervoltage condition.

Since the potential for damage increases with the degree of departure from nominal value, a single overvoltage setting and a single undervoltage setting with a single time delay for each may not provide the protection needed and cause unnecessary interruptions to the generation facility. Relays with multiple overvoltage and undervoltage elements with different pickup and time delay values are better suited to keep the generation facility operating and still protect customers' equipment. If the voltage magnitude is out of tolerance for an unacceptable period of time, the generation facility is disconnected from the transmission system.

#### 7.3.2.2 Under/overvoltage magnitude protection

Three different conditions should be addressed with this protection. The first is sustained operation slightly outside the normal voltage expected by energy consumers. Devices maintained by both the transmission and generator owners are designed to take action to maintain voltage magnitudes during both the normal grid configuration and during intended islanded conditions. The controls of these devices have time delays to achieve the required coordination. These protection elements typically operate for control problems, during a system disturbance when the generation facility fails to separate from the transmission system, or when the resulting load is too large for the capacity of the connected generation.

The second condition is when the voltage magnitude is outside of the power equipment ratings. If the voltage magnitude remains at this level, power equipment may be damaged. The time delay on the voltage elements should be coordinated with the power equipment capability and be significantly faster than the elements set for

operations slightly outside the normally expected voltage. The operation of these protection elements is most likely due to a significant failure of the generation facility and/or its controls or the isolation of the generation with load that is well beyond the facility's ability to maintain the voltage magnitude.

The third condition is when the voltage magnitude has made a significant departure from the normal range. The protection system must respond to this condition as electrical equipment may have a very limited tolerance before damage may occur. The undervoltage pickup and time delay elements are still required to coordinate with line, backup, and breaker failure protection. It is possible that an extended, uncleared fault on the system may be the cause of the voltage departure. Additionally, a severe undervoltage condition can occur when the load demand greatly exceeds the generation capability, perhaps, during an unintended islanding event.

### 7.3.3 Reverse power protection (32R)

Reverse power protection is used to address two main issues: generator motoring and undesirable export of power. The desired directional orientation of the reverse (or directional) power relay depends on its application. For generator motoring, the relay is connected to detect power flow toward the generator. To help prevent the undesirable export of power, the relay is connected to detect power flow into the transmission system.

#### 7.3.3.1 Motoring protection

The motoring power of combustion turbine and diesel generators is very high (25% to 50% of their rated MVA). To protect the transmission system from a possible voltage collapse due to the generators' high power consumption during motoring, the reverse power relay pickup should be set no more than 7% to 10% of the machine rated MVA; see IEEE PES PSRCC WG C12 Technical Report [B4].

The motoring power of steam and hydroelectric turbines (0.2% to 3% of their rated MVA) is insignificant; therefore, these turbines do not generally present a problem for the transmission system.

This is not an issue for WTGs because the inverter system is designed to motor the generator only during startup of the turbine.

For more information on the generator motoring protection, refer to IEEE Std C37.102.

#### 7.3.3.2 One-way power flow

Some generation facilities may not intend to export power to the transmission system. These generation facilities usually operate in parallel with the transmission system and are designed to carry all or part of the local load. When this is the case, the reverse power flow into the system or the lack of power flow into the facility may be used as an indication that a local power source has become separated from the transmission system. The generation facility must be separated from the transmission system any time that the transmission source is lost. A directional power relay (32) is applied for this function and can be used to provide a simple, economical protection scheme to separate generation from the transmission system. The device provides an indirect detection of the loss of transmission source and operates only after the remote transmission breakers have opened.

As discussed more fully in IEEE Std C37.95 [B16], the directional power relay can be applied in two basic forms. The more common form detects power flow back into the transmission system. If there are other consumers connected to the same transmission source, the minimum load of those consumers can be used to derive the minimum setting of the relay, and sensitivity is generally not an issue. However, if no other reliable loads are supplied from the transmission source, the directional power relay needs to be connected to the low side of the interconnecting transformer and set to detect the transformer magnetizing watt loss component. The protective device needs to be a true power-measuring relay that works reliably and is not affected by the characteristics of the connected transmission system.



For modern low-loss transformers, even a very sensitive directional power relay may not be sensitive enough to detect the transformer magnetizing current. In these cases, the generation facility load may be large enough for the directional power relay to detect loss of power flow to the facility as a means to detect a loss of the transmission source.

In all cases, the operation is intentionally time delayed to reduce the probability of misoperation due to normal fluctuations of load/generation at the interconnection. Since the generation must be removed prior to any automatic restoration, the time-delayed tripping should coordinate with any autoreclosing (IEEE Std C37.95 [B16]).

In summary, the directional power relay provides an indirect method of fault detection by sensing loss of the transmission source. It is generally applied when the generation is added to an existing consumer where instrument transformers on the high-voltage side are not available and where there is no intent or risk of exporting power to the transmission system, except, perhaps, for momentary reversals. It may not be possible to set them reliably without causing nuisance trips or the necessary time delay may not be tolerable from a system reliability or security viewpoint. This may be particularly true for multi-phase faults. There are enough issues with this protection strategy that it would typically not be recommended for new installations.

#### 7.3.4 Breaker failure protection (50BF)

The generator owner should install breaker failure protection (50BF) on its generator breaker (Figure 13). The breaker failure protection should send a signal to trip the breaker at the transmission station. Remote backup functions of relays protecting adjacent transmission lines should be coordinated with the breaker failure protection of the generator breaker to allow its operation without unnecessarily removing additional lines from service.

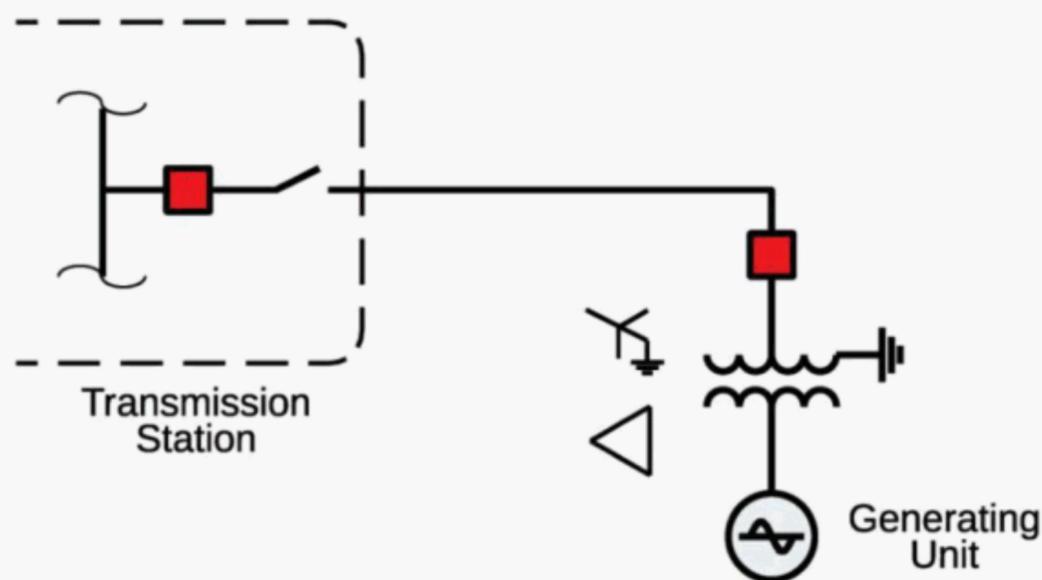


Figure 13—Generator circuit breaker

#### 7.3.5 Power transformer ground time overcurrent protection (51TG)

Ground overcurrent relaying (device 51TG or 67N) is one area where protective device coordination between generation and transmission is required. GSUs and reserve station service transformers are often provided with nondirectional overcurrent relaying designed to protect the transformers from damaging overcurrents caused by internal as well as external faults. These transformers are typically connected grounded wye on the high-voltage side and are sources of ground current onto the transmission system. Transformer ground overcurrent relaying can also provide backup protection for transmission faults, especially, where no transmission protection redundancy or breaker failure protection is provided.

Transformer ground overcurrent relaying primarily protects the transformer by coordinating with the transformer's damage curve. If providing backup transmission system protection is desired, then the transformer ground overcurrent element settings must also coordinate with the transmission line ground overcurrent relay settings, typically device 67N, while also accommodating anticipated system imbalance. This may become difficult to do at multi-unit generating stations with many transmission lines. Ideally, each transformer ground overcurrent element would be set to protect the transformer and also to detect line-end faults (with the remote terminals open) on each of the lines out of the station. It is not always possible to set each of the transformer relays to provide backup transmission protection for each of the lines at the station; in these cases, redundant line and breaker failure protection should be provided on the transmission system. If using the transformer ground relay is desired to protect against noncleared transmission system faults, the following should be considered for its settings:

- It should be set to pick up for the worst-case (lowest magnitude) end of line fault on the transmission lines exiting the station.
- It should be set above the maximum expected system imbalance neutral current.
- It should be set to have sufficient time delay to coordinate with the worst-case (slowest) clearing time on the transmission system, including breaker failure clearing times. Some margin above this clearing time should be allowed (generally, 12 to 30 cycles).
- The relay characteristic curve should match what is used by the transmission line relay.

Figure 14 and Figure 15 provide an example of coordination of a transformer 51TG relay and a line 67N relay.

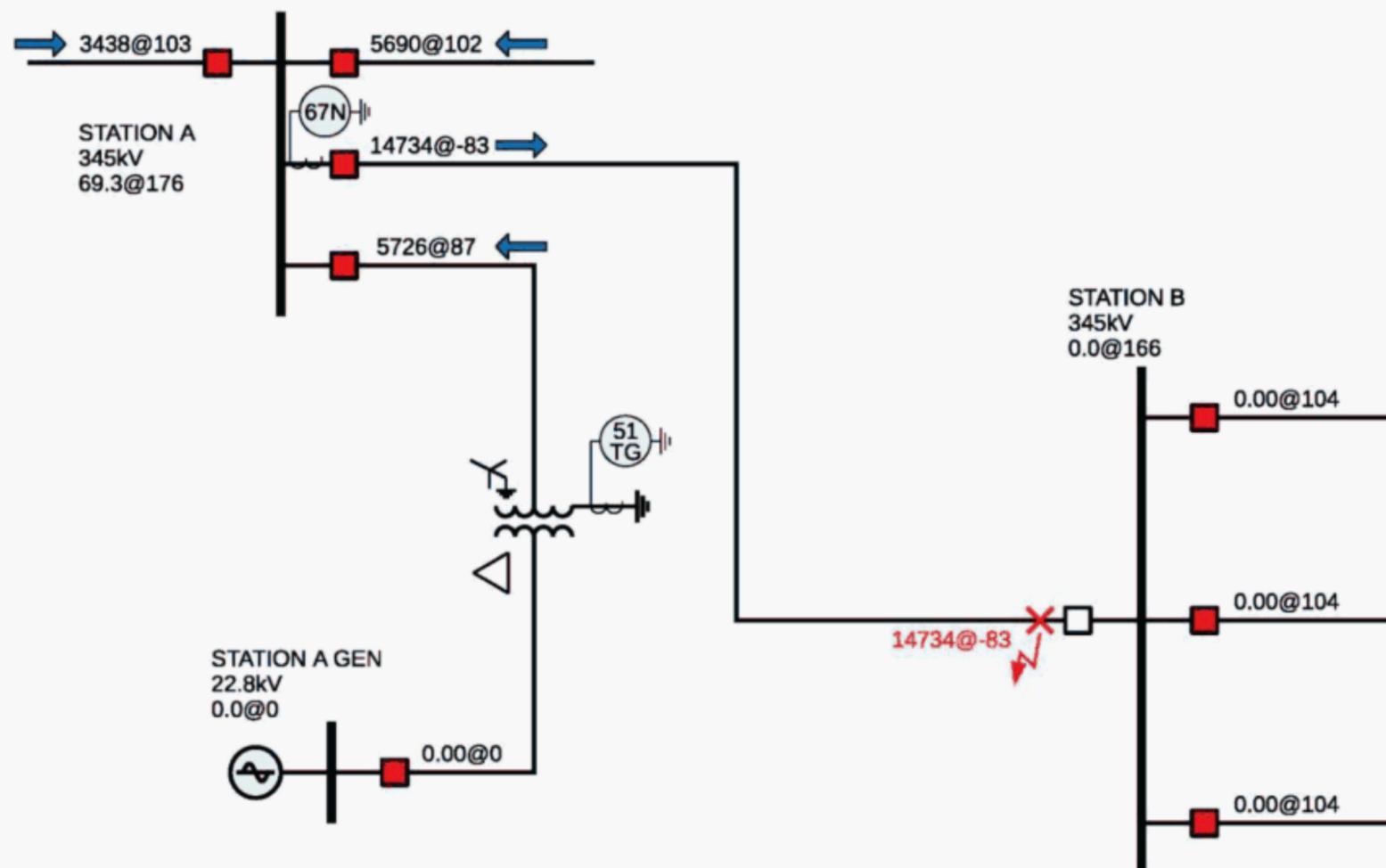


Figure 14—Transmission system segment showing line end open ground fault

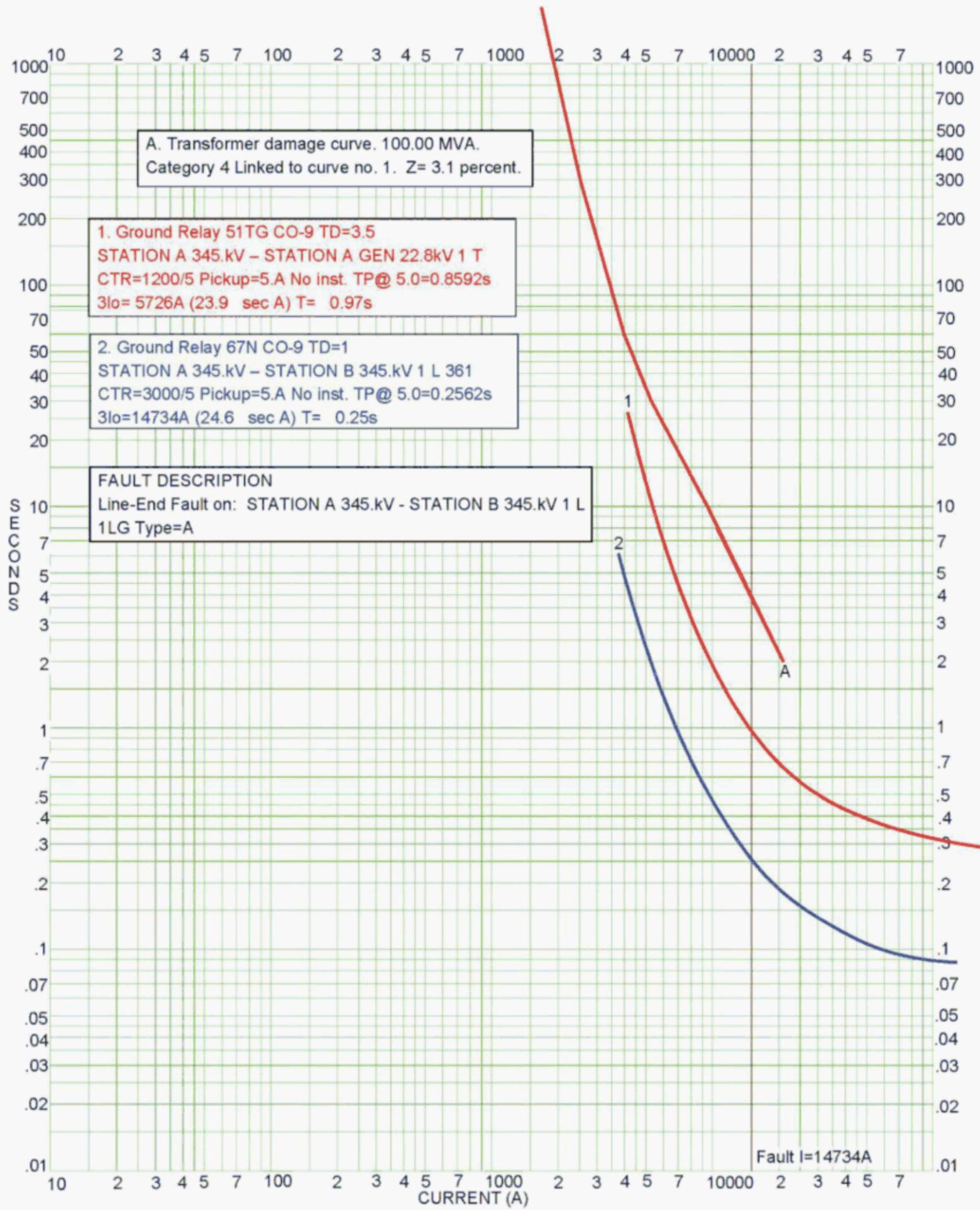


Figure 15—Time overcurrent for line end open ground fault

### 7.3.6 Frequency protection (81)

Frequency protection, both underfrequency and overfrequency, is applied at the generation facility (IEEE Std C37.106 [B19]). It is used to protect the turbines from damage that can result from operating at off-nominal frequencies. It is not always required for hydroelectric turbines since some of these are not subject to damage by operation at off-nominal frequency. Operating durations for off-nominal frequencies of various turbines are available from the manufacturer.

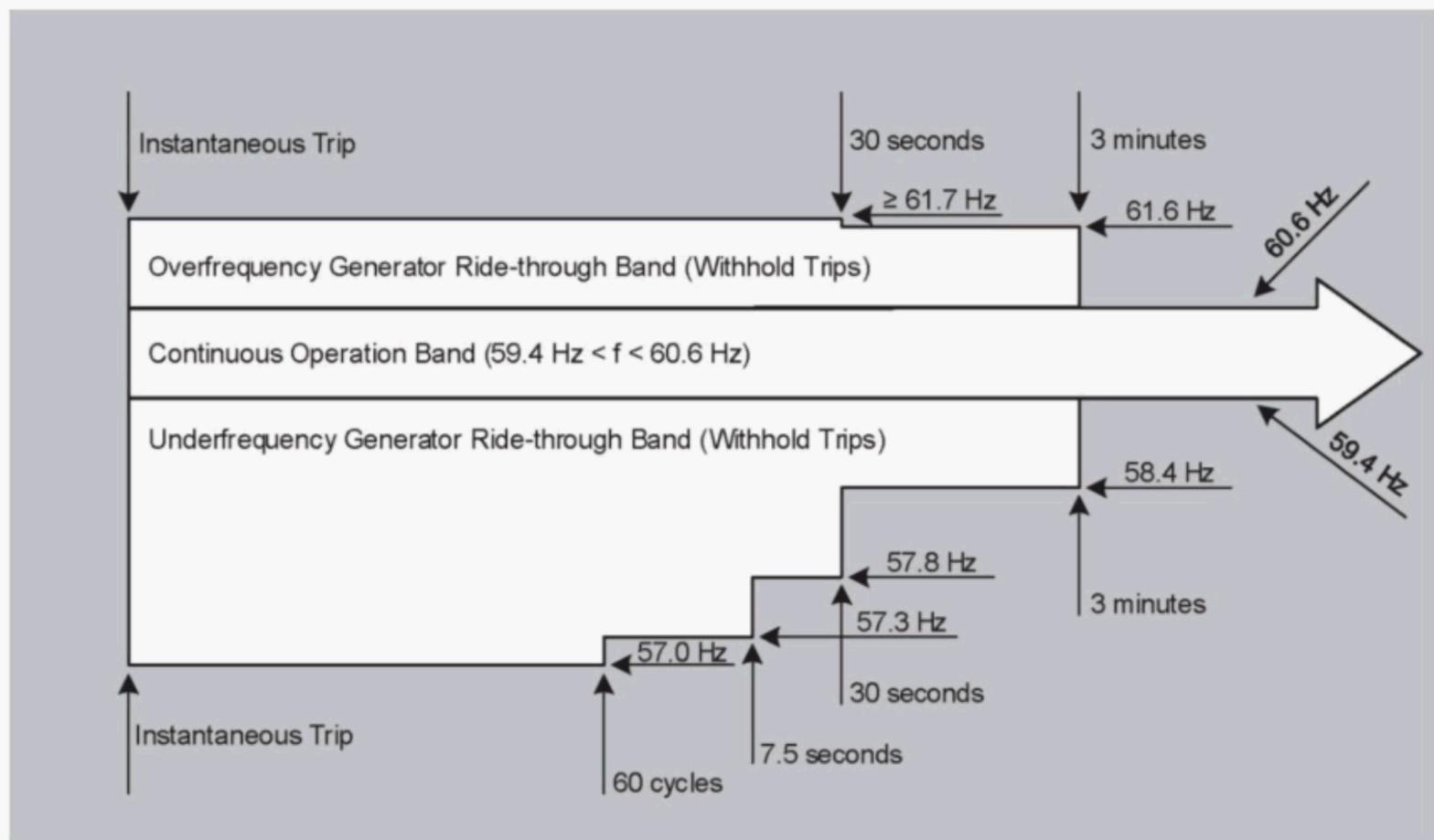
In addition to protecting turbines from damage, frequency protection is often used to detect operational islands. If an area separates into an island, an imbalance between generation and load may occur within the islanded system. This imbalance results in the generator either accelerating or decelerating with a corresponding frequency change, depending on whether load is less than or greater than the available generation. Frequency relays detect this change and disconnect the generation from the system.

Removal of the generation during an islanding event helps prevent damage to a customer's equipment within the island. If the generation is not removed, voltage and frequency within the island can quickly drift outside of acceptable levels. The voltage waveform might also be unacceptable, especially if the islanded generation is asynchronous. Even though the system is synchronized prior to the formation of the island, if the frequency of the islanded system drifts from its nominal value, it quickly loses synchronism with the transmission system. The islanded system should not be restored until its generation is disconnected or resynchronized with the transmission system.

A conflict can result when using underfrequency relays as anti-islanding protection because using narrow limits on the frequency trip points is desirable to provide quick removal of the generation when an island is created. However, there are interconnection-wide limits to how quickly generation can be removed at particular frequency levels. These limits are part of the interconnection-wide off-nominal frequency load-shedding plans, and their purpose is to help prevent generation from being removed before load is shed to try to arrest the frequency decline when an underfrequency event occurs on the interconnection. If generation is disconnected during the underfrequency event, the drop in frequency is magnified, perhaps beyond the ability of the load shedding scheme to stop it. Therefore, the load shedding plans require generation to stay online long enough to give the load shedding scheme a chance to arrest the frequency decline. If too much generation is dropped during an overfrequency event, an underfrequency event could quickly develop. For an example of generation tripping and ride-through requirements, see [Figure 16](#) for illustrative purposes only; the applicable regional requirements should be followed. This can result in a conflict between the operational goals of the transmission owner and the generation owner. The transmission owner needs to keep the transmission system intact while the generation owner needs to protect generating equipment from damage due to off-nominal frequency operation. Care should be taken to help ensure generation equipment manufacturer recommendations do not conflict with regional ride-through requirements. For more information for off-nominal frequency protection, refer to IEEE Std C37.106 [B19].

An additional application for which frequency protection may be implemented is backup protection when the system experiences departures from nominal frequency values. The function operates after or during an islanding condition when primary and normal backup protection has failed to disconnect generation and one of the following occurs:

- An uncleared fault remains on the islanded portion of the system and affects its frequency.
- The frequency departure is too great for the generation to recover by responding to the system imbalance.
- The load-generation island that was created as a result of the initial frequency departure or fault is still too imbalanced for the generation to maintain the nominal frequency.



NOTE—Shaded areas are tripping zones with no restrictions or requirements.

Figure 16—Illustration of generator trip point and frequency ride-through requirements

### 7.3.7 Bus differential protection (87)

If the ground grids of the generation facility and the transmission system bus are tied at the point of interconnection, then their interconnection is most commonly treated as a bus. When this is the case, the bus can be protected in accordance with the bus protection practices discussed in IEEE Std C37.234 [B22]. In cases where the ground grids are not connected, or occasionally even when the grids are tied together but circumstances warrant otherwise, the point of interconnection may be treated as a line. See 7.3.8 for more information on this subject.

Several considerations should be made when developing the design and settings for the bus differential protection. Such considerations include the selection of the bus differential scheme, possible outage constraints, the CTs that are available for use, and the lengths of CT cable runs.

A variety of different bus protection schemes are available for general use. Refer to IEEE Std C37.234 [B22] for explanations of various bus protection schemes. Regardless of what type of scheme is selected, if the bus differential relaying is to be replaced, then outages must be considered. Obtaining a generator outage long enough to replace a bus differential relaying scheme might not be economically feasible. In absence of the existing redundant bus differential relaying scheme, a lack of adequate outage times could be a reason to cancel a project to replace the bus differential relaying.

The CTs that are available for the bus differential scheme, as well as the available CT ratios on these various CTs, have a significant impact on the scheme selection. The generator owner may need to furnish a dedicated CT input to the bus differential protection scheme at the interconnection to provide coordinated bus differential protection of the bus. In addition, the CT ratings are important because the CT voltage ratings and the possibility of CT saturation influence the reliability of the scheme. Lastly, cable impedance can be quite substantial if the cable runs are lengthy; therefore, the distance between station and generation CTs is important to know. If cable impedances do present problems with burden, possible solutions include increasing the current cable size or running multiple current cables in parallel to lessen the burden in the CT circuit.

### 7.3.8 Tie line current differential protection (87L)

If the ground grids of the generation facility and the transmission system bus are not tied at the point of interconnection, a tie line connecting them should be protected in accordance with the transmission line protection practices per IEEE Std C37.113 to accommodate the ground grid isolation. This line is typically an electrically short transmission line and lends itself best to a digital communication-based current differential protective function, which may be beneficial for the interconnection protection for the following reasons.

- The current differential function, generally, is not affected by weak infeed conditions, which may be present at interconnections where the generation facility's fault MVA capacity is lower than the fault MVA capacity of the transmission system.
- The function requires only line current values; VTs are typically not required for the scheme although they may be needed for the backup protective elements or to provide protection during a communication issue.
- The selectivity of the function and the simplicity of its relatively few settings may be advantageous as compared to other inherently overreaching schemes such as overcurrent and distance protective functions. The current differential protection would react to faults on the tie line only while the overcurrent and distance functions would be overreaching.
- The current differential function is dependent only on fault current levels on the protected line. Its pickup setting needs to be low enough to detect all types of faults on the line yet high enough to minimize the probability for the relay to operate for external faults in the presence of CT or other measuring errors.
- If the step distance function is applied, it may be susceptible to unwanted operation during high load conditions and should be studied for the security of the scheme during power swings. The current differential function is unaffected by line loading and power swings. High load flows through the protected line are not a concern when the current differential schemes are applied as the current summations for the through current result in zero net difference into and out of the line.

For more information on current differential protection, refer to IEEE Std C37.243 [\[B23\]](#).

## 7.4 Protection redundancy

The protection schemes for interconnections should be designed so that no single component failure can prevent the isolation of faults and/or failed equipment. This may require providing redundant or backup protection schemes with separate sensing sources, separate trip paths, dual trip coils on breakers, separate control power supplies, etc. (IEEE PES PSRCC WG C16 Technical Report [\[B5\]](#), IEEE PES PSRCC WG I19 Technical Report [\[B8\]](#)).

The objective of the protection redundancy design should be to achieve a balance in meeting the technical requirements, addressing reliability concerns, considering costs, and maintaining consistency in design standards with the goal of achieving a robust design.

Another important consideration is the time to repair a defective component in the protection system of the interconnection. This time may dictate a required degree of redundancy so the protection of the interconnection is not affected.

Aspects such as dissimilar operating principles, diverse path communication channels, and different hardware platforms should also be considered when evaluating the redundancy of the protection scheme at the interconnection.

## 7.5 Interconnection tripping

The generation facility should be capable of isolating itself from the interconnection to the transmission system in the event of an uncleared system fault, abnormal operating condition, or equipment or system failure.

For generating stations without black-start facilities, an alternative to tripping the tie line at the point of interconnection is to trip the generator breaker. This leaves the generating station bus energized or at least connected to the transmission system and enables the restoration of the generation facility once the system has returned to normal.

## 7.6 Transmission line autoreclosing near generation facility

The autoreclosing of breakers on transmission lines at or adjacent to the interconnection can be potentially damaging to the generation owner's equipment that is in electrical proximity to the lines. The transmission owner may not eliminate autoreclosing of overhead transmission lines near the generation facility because that could significantly affect the reliability of service to transmission customers. In order to mitigate possible negative effects of line autoreclosing on generation facilities, the transmission owner may have the following options:

- a) Not autoreclose lines for three-phase faults on the transmission system. Such faults are typically considered to be the most severe type of faults in the system.
- b) Autoreclose a line first at a remote terminal followed by synchronism check reclosing of the breaker at the interconnection bus (sequential reclosing).
- c) Delay autoreclosing for all faults (for an example, for 10 s).
- d) Use a single-shot autoreclosing and block further attempts if the fault is of a sustained nature.
- e) Use the single-phase tripping and autoreclosing scheme by tripping only the faulted phase and delay autoreclosing until the secondary fault arc is extinguished. The benefit of this scheme is that the remaining connected phases tend to hold the generating units in synchronism during the first clearing attempt. Keeping generating units in synchronism minimizes power swings and helps to maintain system stability.
- f) Autoreclose using voltage supervision to help ensure the line is de-energized before a reclose attempt is made.
- g) High-speed autoreclosing could be allowed in configurations with more than two lines. One line could be out of service with the remaining lines left in service to ensure the generator would remain paralleled to at least one line. Therefore, a high-speed autoreclose on the lines would not lead to an out-of-phase parallel condition.

Also, the transmission owner may install additional equipment to minimize the potentially adverse effects of autoreclosing. This usually consists of communication and/or control equipment to disconnect the generation facility (or to confirm that it is disconnected) before a transmission line is reclosed.

In cases where the substation at the interconnection has two transmission lines, a line side single-phase voltage-sensing potential device should be installed at the remote terminal of each line. This serves the purpose of bus voltage checking for an autoreclosing attempt at the remote test-energized line terminal.

Autoreclosing is problematic for transmission lines with tapped connections. A DTT scheme can be installed to force the disconnection of the generation in case the transmission system breakers are opened. Live-line voltage supervision could be added to the autoreclosing to help ensure the generation is disconnected prior to an autoreclosing attempt. See [7.7](#) for more information on DTT.

For more information on transmission line autoreclosing, see IEEE Std C37.104 [\[B18\]](#).

## 7.7 Communication channel implications/DTT requirements

DTT is a scheme that, based on a local condition, sends a trip signal via a communication channel to remote substations to trip their breakers. As an example, a local breaker failure condition may send a trip signal to remote substations. For more information on DTT, see IEEE Std C37.113 and IEEE Std C37.119 [B20].

DTT schemes in generation-to-transmission interconnections are typically required when the generator backup protection and/or line relays cannot detect a transmission line or bus fault. The scheme is also utilized to help prevent the formation of a sustained unintended island when the load to generation ratio in the island is low. This situation can occur after a fault or opening of both remote line terminals when there are other substation loads along the transmission line as illustrated in Figure 17.

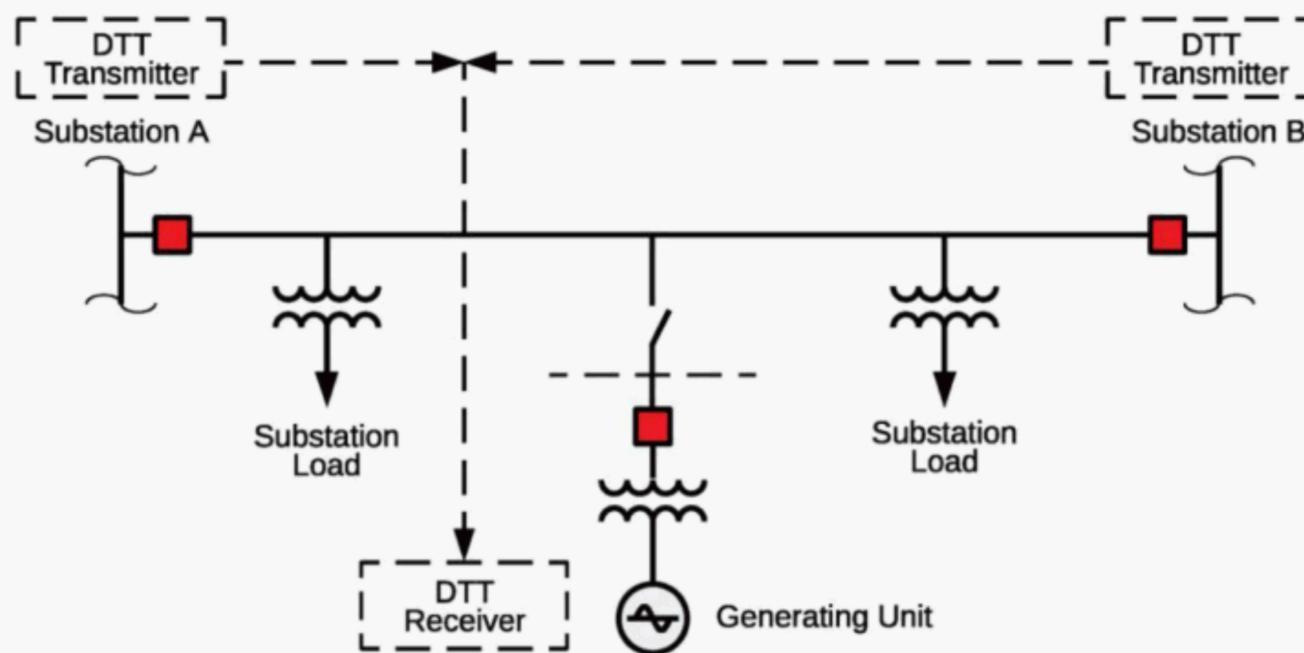


Figure 17—DTT scheme in generation-to-transmission interconnection

If the generation is connected via a tie line with no tap loads to the transmission system, anti-islanding DTT may not be required.

When DTT is specified, communication device(s) and communication channel(s) are required between the generating station and each of its remote ends.

If there is an existing DTT scheme between the two remote ends, it may be modified to receive a new signal/channel from the remote ends to the substation at the interconnection. It is also possible to use a separate equipment/channel for tripping the remote substation(s).

Another example of a DTT scheme is shown in Figure 18. In this example, the generator could island with the connected load if the path from the generator to the transmission system is opened or generator protection cannot detect a fault on Line 1 (between Bus A and Bus B) or on Line 2 (between Bus B and Bus C). This can occur if CB 1 or CB 2 or CB 3 is opened.

To help prevent an island or a sustained fault under these conditions, DTT can be initiated from the circuit breaker open status and/or protective elements (i.e., bus differential or line relaying) as follows:

- DTT 1 is initiated to trip CB 4 when CB 1 is open or tripped via protection elements.
- DTT 2 is initiated to trip CB 4 when CB 2 or CB 3 is open or tripped via protection elements.
- DTT 3 is initiated to trip CB 4 when CB 5 is open or tripped via protection elements.



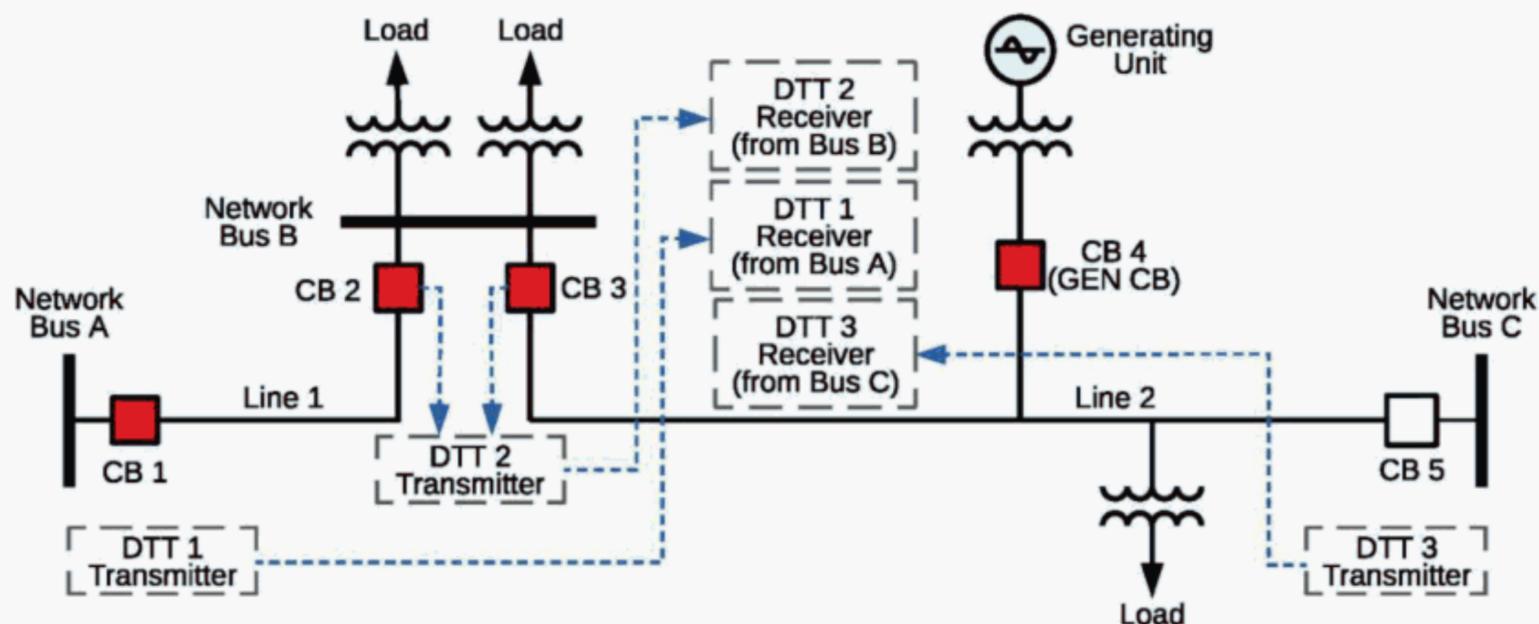


Figure 18—DTT scheme on a radial line with distribution load

It should be noted that, when CB 5 at Bus C is closed and has a source behind it, DTT 1 and DTT 2 are not required and should be disabled either automatically or manually.

If CB 5 is a normally open breaker that is rarely closed, an operating agreement between the transmission and generator owners may be used, in which the generator remains offline when CB 5 is closed while Line 1 is out of service; such an agreement removes the need for DTT 3 at Bus C.

## 7.8 Additional considerations

### 7.8.1 Tapped generation connections

Interconnection location, transformer connections, and type of protection schemes can have a significant impact on existing line protection. All faults in the vicinity of the transmission owner's zones of protection should be cleared from the transmission system in the shortest time interval possible while observing proper coordination of both the transmission and the generator owners' devices. Primary and secondary (or backup) devices or elements may be owned by separate entities depending on local practices and philosophies. This coordination study may be complex and may present challenges to arrive at the desired protection package(s). Completed settings are required to be reviewed for coordination with the owner of the remote terminal.

#### 7.8.1.1 Generation location

For tapped connections, the location of the tap can have impacts on protection schemes that require consideration in the following areas:

- Line relay coordination with generation relays
- Apparent impedance and infeed effects for both phase and ground relays

#### 7.8.1.2 Line relay coordination

Line relay coordination on the line terminal with the tapped connection may be affected as shown in [Figure 19](#). A tap too close to a line terminal may result in miscoordination of Zone 1 and/or instantaneous overcurrent elements with the generation facility relays. If coordination can be achieved, the resulting underreach of the Zone 1 elements may also lead to coordination issues of the upstream remote terminals. If the tap location cannot be moved, a switching station may need to be installed.

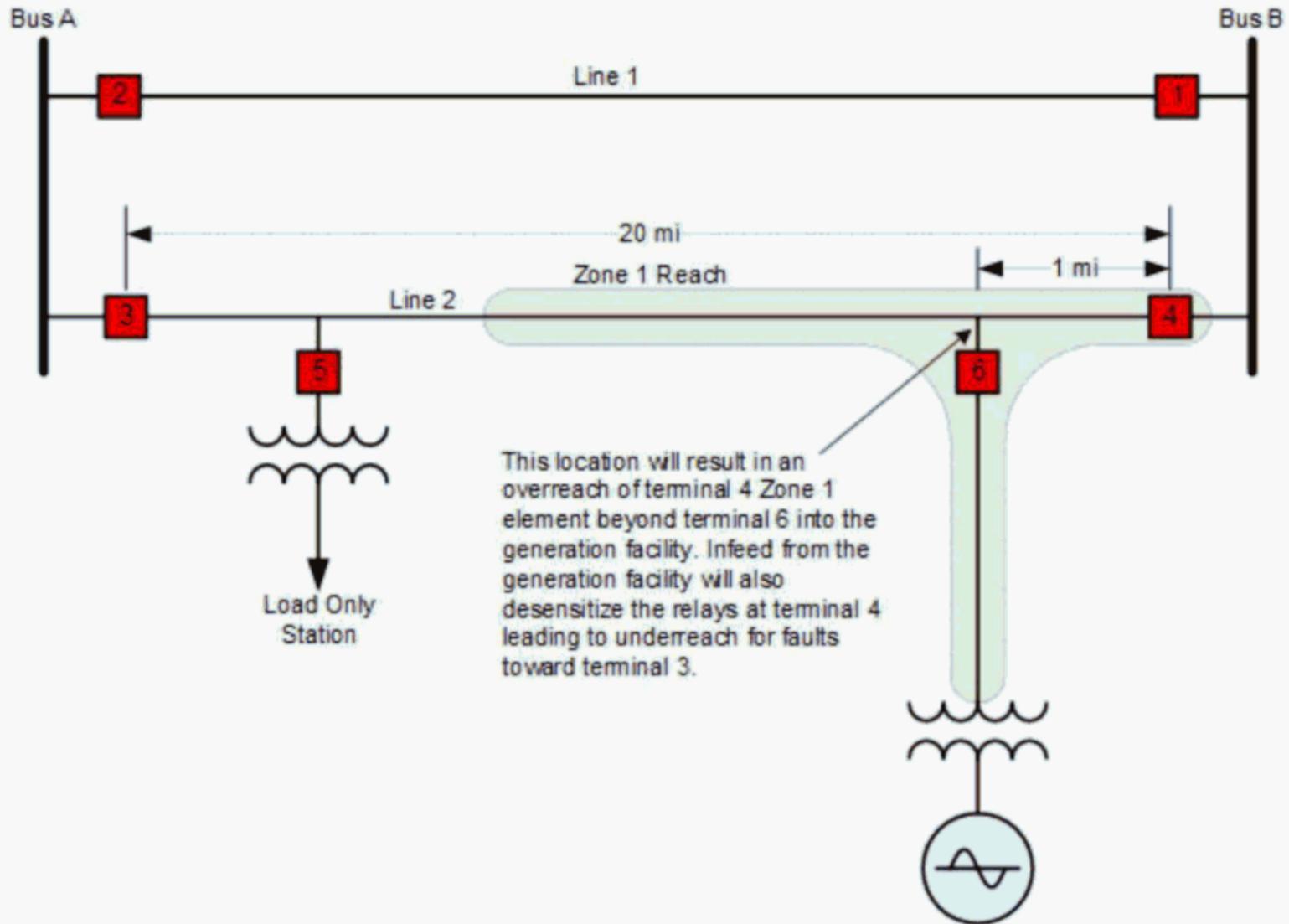


Figure 19—Example of tapped connection too close to station

### 7.8.1.3 Apparent impedance and infeed effects

#### 7.8.1.3.1 Phase distance relays

Tapped generation introduces infeed during fault conditions that can desensitize remote terminal line relays. Refer to [Figure 20a](#), which shows a line protected by distance relays. Distance relays measure fault impedance from the line terminal to determine the distance between the fault and the terminal. That value is compared against predetermined values (based on settings) with some assumptions for simplification (the line is homogenous and fault resistance is negligible). The relay declares an in-zone fault if the measured impedance is less than a preset value.

For a phaseA-to-B fault, the apparent impedance is measured by the relay to the fault, as shown in [Figure 20a](#), and calculated as follows:

$$Z_{AB} = \frac{V_{AB}}{I_{AB}} = Z_{1F} \quad (1)$$

where

$V_{AB}$  is phaseA-to-B line voltage at the relay location

$I_{AB}$  is phaseA-to-B loop current at the relay location

$Z_{AB}$  is apparent impedance measured across phaseA-to-B loop formed by the line fault

In the absence of infeed from tapped generation, this impedance is equal to  $Z_{1F}$ , which is the positive sequence impedance of the line from the relay location to the fault.



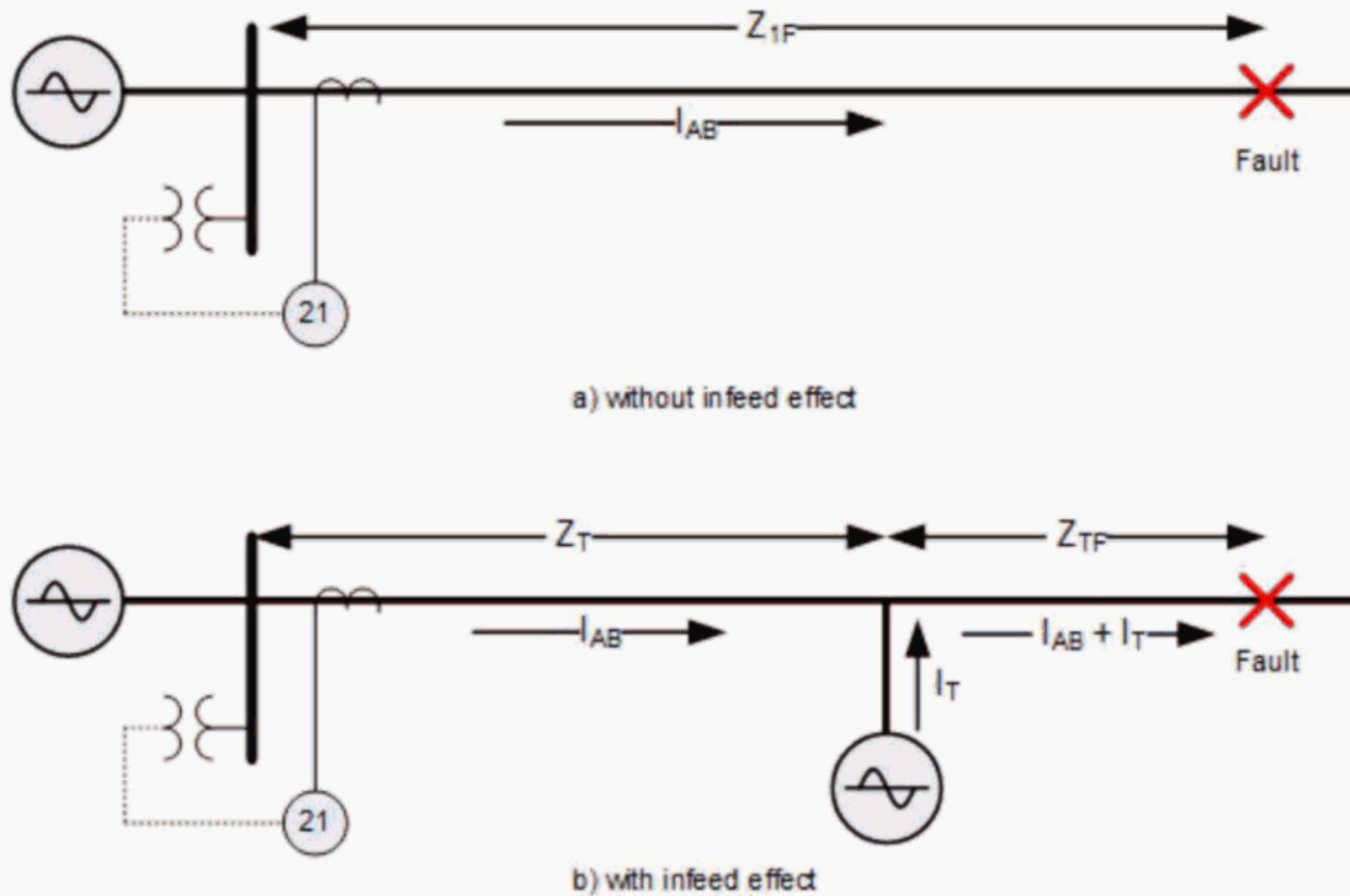


Figure 20—Line protection using distance relay

Figure 20b shows the case when tapped generation is added to the line. With infeed from the tapped generation, the measured voltage  $V_{AB}$  at the relay location is different and given as follows:

$$V_{AB} = I_{AB} \times Z_T + (I_{AB} + I_T) \times Z_{TF} \quad (2)$$

where

- $Z_T$  is positive sequence impedance of the line from the terminal to the tap location
- $Z_{TF}$  is positive sequence impedance of the line from the tap location to the fault
- $I_T$  is infeed current between the phase A-to-B loop to the fault formed by tapped generation

Using the local voltages and currents,  $Z_{AB\_INFEED}$ , which is apparent impedance measured by the relay across phase A-to-B formed in presence of infeed from tapped generation, is still given as follows:

$$Z_{AB\_INFEED} = \frac{V_{AB}}{I_{AB}} \quad (3)$$

$$Z_{AB\_INFEED} = Z_T + Z_{TF} \times \frac{I_{AB} + I_T}{I_{AB}} \quad (4)$$

$$Z_{AB\_INFEED} = Z_T + Z_{TF} \times \frac{I_{AB} + I_T}{I_{AB}} \quad (5)$$

The impedance from the terminal to the fault measured by the relay is now greater than the actual value. The increased value of impedance ( $Z_{ABF\_INFEED}$ ) above  $Z_{1F}$  from a terminal to a fault (as measured by the relay) requires a greater relay reach to maintain the relay's ability to detect the fault as dependably as before the addition of the tapped generation. This is referred to as phase fault desensitization. Elmore [B2] provides a more detailed explanation of this phenomenon. The extent of the phase fault desensitization depends on the following:

- Available fault contributions (or source strengths) from the transmission system and tapped generation
- Distance of the tapped connection from the line terminal

The infeed issue can be exacerbated when interconnecting a strong tapped generation facility in proximity of a weak transmission system terminal and, under certain credible contingencies, may require unusually large reach settings and time delays for the transmission system distance relays. This is especially applicable when the line protection is meant to provide breaker failure coverage at the remote terminal. If tapped generation is operated intermittently, protection studies, typically conducted by the transmission owner using a single credible contingency and applicable generation facility interconnection studies, should be expanded to include more than one contingency. The additional contingencies typically include unavailability of intermittent generation. The coordination of overreaching protection elements may need to be checked when the tapped generation is out of service.

The resulting increased distance reaches should be checked to verify they do not encroach on line loading limits and meet applicable regulatory loadability requirements. Since lower voltage sub-transmission circuits may have relatively high series resistance (i.e., the low characteristic angle) compared to that of higher voltage lines, the load blinder's impact on the protection dependability is reviewed before accepting a tapped connection. System planners are also asked to assess an impact of long time delays on system stability as well as on power quality.

**Ground distance relays** The addition of new tapped generation to a transmission line terminal can have a significant negative impact on the ability to detect ground faults at the existing line terminal due to fault current division between the existing and new tapped generation. Using symmetrical component networks for a line-to-ground fault, this subclause illustrates this phenomenon, which is also referred to as ground fault detection desensitization. Elmore [B2] and Nagpal et al. [B28] provide a more detailed explanation and examples of this phenomenon. Besides generator and path impedances, the winding connection of the transformer, interconnecting the new tapped generation to the existing transmission line, typically has the most influence on desensitization. Since transmission systems are typically effectively grounded, it is highly desirable to have effectively grounded transformer connections, which limit temporary overvoltages on the healthy phases in cases when the new tapped connection is a sole generation feeding a ground fault. On the other hand, effectively grounded tapped connections typically desensitize ground protection on the remote terminals of transmission lines.

Figure 21 shows a transmission line with a tapped connection via a transformer, which has grounded wye-delta winding configuration. Figure 22a shows the symmetrical component network for a solid line-to-ground fault prior to the interconnection or assuming that the disconnect (D1) at the tap location is open. For illustrative purposes, the resistive component of all the network elements has been ignored. The ground overcurrent protection element installed at the transmission system's terminal (51N) sees full ground fault current. After tapped generation is added, the ground fault contribution seen by this element reduces; therefore, the line protection element desensitizes. The worst-case reduction in ground fault contribution from the transmission system's terminal for this type of transformer connection is when the tapped generation is offline but the transformer is still connected to supply the plant auxiliary load. This reduction in the ground fault contribution from the transmission system is the largest for this operating scenario since the positive and negative sequence source impedances to the fault are exactly the same as in the scenario before the tapped generation was connected. However, the zero sequence impedance is reduced due to the parallel zero sequence paths. Thus, the tapped generation contributes no current to the fault, but its step-up transformer may easily contribute a large portion of the zero sequence current, especially if the zero sequence impedance of the transformer is small. This is a common operating mode for the generation operated intermittently that may obtain station service supply via a GSU. Figure 22b shows symmetrical component networks under this condition, i.e., when tap location disconnect (D1) is closed and the unit breaker (CB2) is open. The ground fault contribution is now divided between the transmission system's terminal and the interconnection transformer depending on their relative zero sequence impedances.

If the reduction in ground protection sensitivity caused by solidly grounded tapped generation is unacceptable, the high-voltage side connection of the GSU may be evaluated to be changed from solidly grounded to either impedance grounded or ungrounded (delta connection). The zero sequence impedance of the tapped generation path becomes larger for the impedance grounding or infinite for the delta connection. During ground faults, these connections may cause temporary overvoltages, which may require other mitigation methods as discussed in 7.8.1.5.

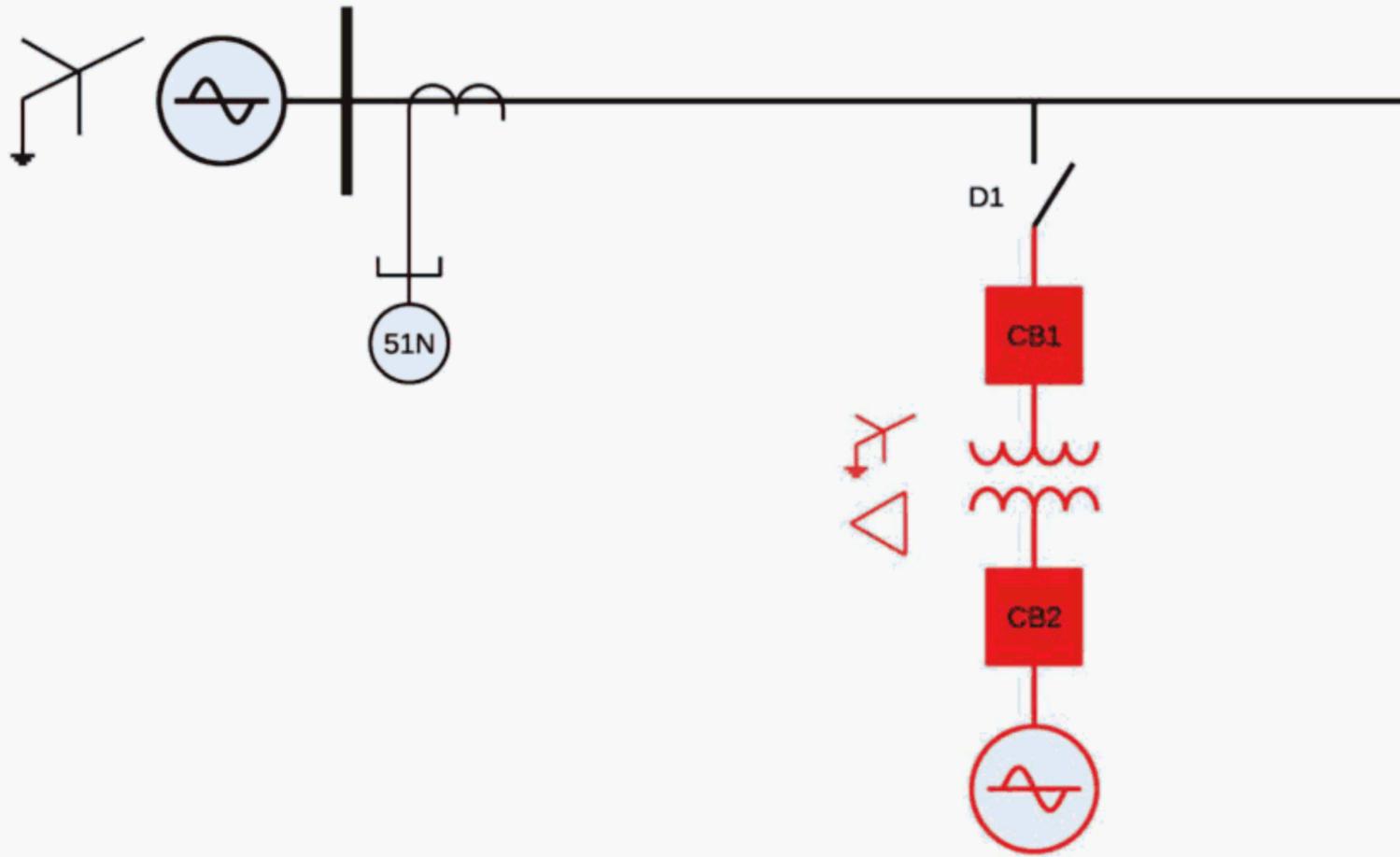


Figure 21—Tapped generation interconnected through a wye-delta transformer

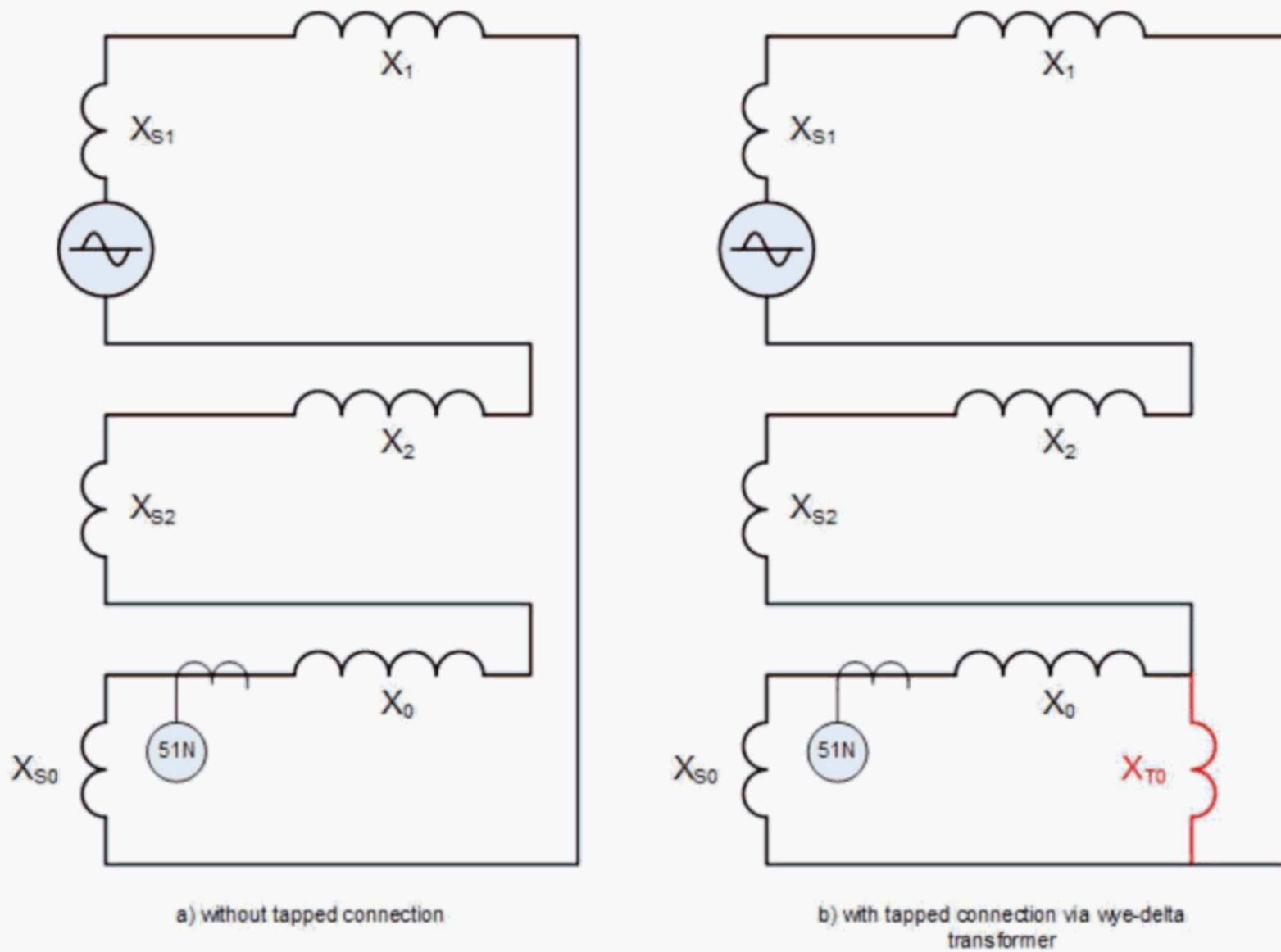


Figure 22—Zero sequence fault current distribution for a solid line-to-ground fault

#### 7.8.1.4 Use of line current differential protection

Tapped generation forms multi-terminal lines unless a switching station is installed as a transmission system upgrade in place of the tap. Utilizing line current differential protection can mitigate the phase and ground relay challenges (apparent impedance and infeed effects) where applicable. By measuring and summing currents from all line terminals, infeed currents are included in the summation, and impedance is used for fault location (or backup schemes) only.

Line current differential protection is a reasonable choice for multi-terminal configurations but may be limited by the capabilities of the chosen protective relaying devices, available communication media, and costs of upgrading both.

The maintenance requirements of this protection not only are increased due to the number of terminals and communication channels, but also may need to be coordinated with each of the terminals, which may have different owners.

For further discussion, see [7.3.8](#).

#### 7.8.1.5 Temporary overvoltage and mitigation

Typically, transmission systems are effectively grounded systems and interconnection of an ungrounded source is usually undesirable. In some cases, after completing a careful protection study and a detailed electromagnetic transient analysis, the transmission system may accept ungrounded or resistance-grounded neutral GSU winding configurations to reduce the desensitization of its own ground protection. However, this may subject transmission equipment to overvoltages.

In-depth transient analysis is used to assess these overvoltages. A transmission owner may not permit even a momentary operation of an isolated system energized by an ungrounded generator when damaging overvoltages can potentially develop due to self-excitation. The alternatives discussed below can address such overvoltage issues.

Fast generator terminal and time-delayed transmission terminal tripping schemes can be employed to minimize subjecting transmission equipment and customers to even momentary overvoltages during the clearing of ground faults. A delayed trip at the transmission terminal is used to help avoid the race between the opening of line and generator breakers (IEEE Std C37.233 [\[B21\]](#)).

As a secondary countermeasure, one set of surge arresters, having a lower voltage rating than the other arresters, may be added to the network that is potentially exposed to overvoltage. These are referred to as sacrificial surge arresters. This method is relatively complex and involves coordination between several components for proper operation. Therefore, it must be agreed upon by both the transmission and generator owners.

[Figure 23a](#) shows a simplified one-line diagram for a generation facility connected to the transmission system by a transmission line, with the high-voltage winding of the GSU connected in delta. The line's protection is shown at both the transmission and generation terminals. For this configuration, in absence of pilot protection, a single line-to-ground transmission fault would be first cleared by the transmission line terminal(s) followed by the opening of the generation terminal by time-delayed zero-sequence overvoltage protection on the high-voltage side of the GSU. Between the time of opening of the transmission line and the generation terminals, the ungrounded generation facility would remain connected for a number of cycles to the ground fault. During that time, the voltage rise can exceed 1.73 per unit due to the combined effects of neutral shift and voltage amplification resulting from series resonance near power frequency in the presence of self-excitation (Nagpal et al. [\[B28\]](#), [\[B29\]](#)). Therefore, mitigation methods such as DTT with a sacrificial surge arrester (described above) should be considered to reduce the overvoltage condition.

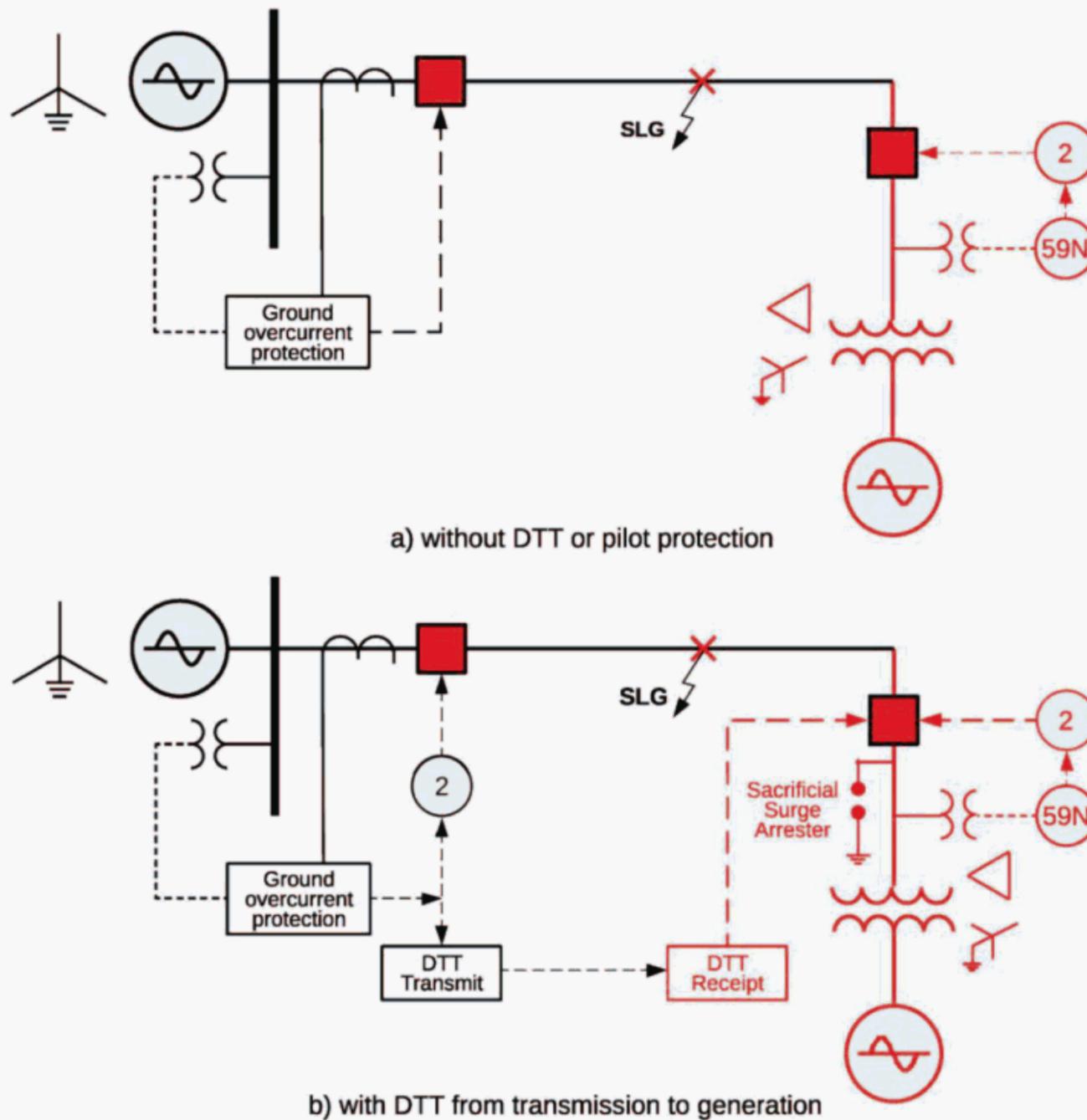


Figure 23—Ungrounded generation-to-transmission interconnection

Figure 23b shows the implementation of this mitigation scheme to help avoid high temporary overvoltages during the clearing of ground faults on the line. The line's ground overcurrent protection at the transmission terminal detects the fault, immediately sends a DTT to the line's remote terminal at the generation facility, and delays tripping the transmission system's breaker by several cycles. The protection at the generation terminal initiates tripping as soon as it receives the DTT. The time delay at the transmission terminal is the sum of the propagation delay in sending and receiving the DTT, including any auxiliary delays, and the generation facility's breaker total clearing time, with some margin.

In the event of a failure of the DTT, the sacrificial surge arrester acts as a last line of defense because it, being the weakest element, would be the only power component that would fail. The desired location of the sacrificial surge arrester shown in Figure 23b is between the generator breaker and GSU. The generating unit cannot reconnect until the failed arrester(s) are identified and replaced; however, the faulted line can be quickly reclosed and back in service after the generator breaker has opened, irrespective of any arrester failure at the generating unit.





51V-R or 51V-C relays are appropriate if transmission lines are protected by overcurrent protection elements such as directional time overcurrent. If the transmission lines are protected by distance relays, distance relays (21) should be used for backup protection.

For more information on generator voltage-controlled/voltage-restrained overcurrent protection, refer to IEEE Std C37.102.

## 7.9 Settings considerations for renewable energy sources

### 7.9.1 Wind power plant settings considerations

Wind power plants share many similar characteristics with conventional power plants, but there are a few items that make these plants unique. Some of these unique items have an impact on the design of the protective relaying for the interconnection of these plants to the transmission system. Many conventional power plants are typically composed of a small number of large generating units. The fault current contribution from a synchronous machine is independent of the power output of the unit before the fault; however, the fault current magnitude from the plant varies with the number of generators connected before the fault. This is also generally true for wind plants, but the variability is much greater due to the number of smaller generators that make up the plant. The size of land-based WTGs is typically in the range of 1 MW to 5 MW (offshore WTGs are typically larger). For instance, a 100 MW wind plant made up of 2 MW WTGs has 50 generators. The fault current from this plant varies from the output of none to 50 generators depending on the operation of the plant before the fault. [Figure 26](#) is an example of a one-line diagram for a typical wind plant.

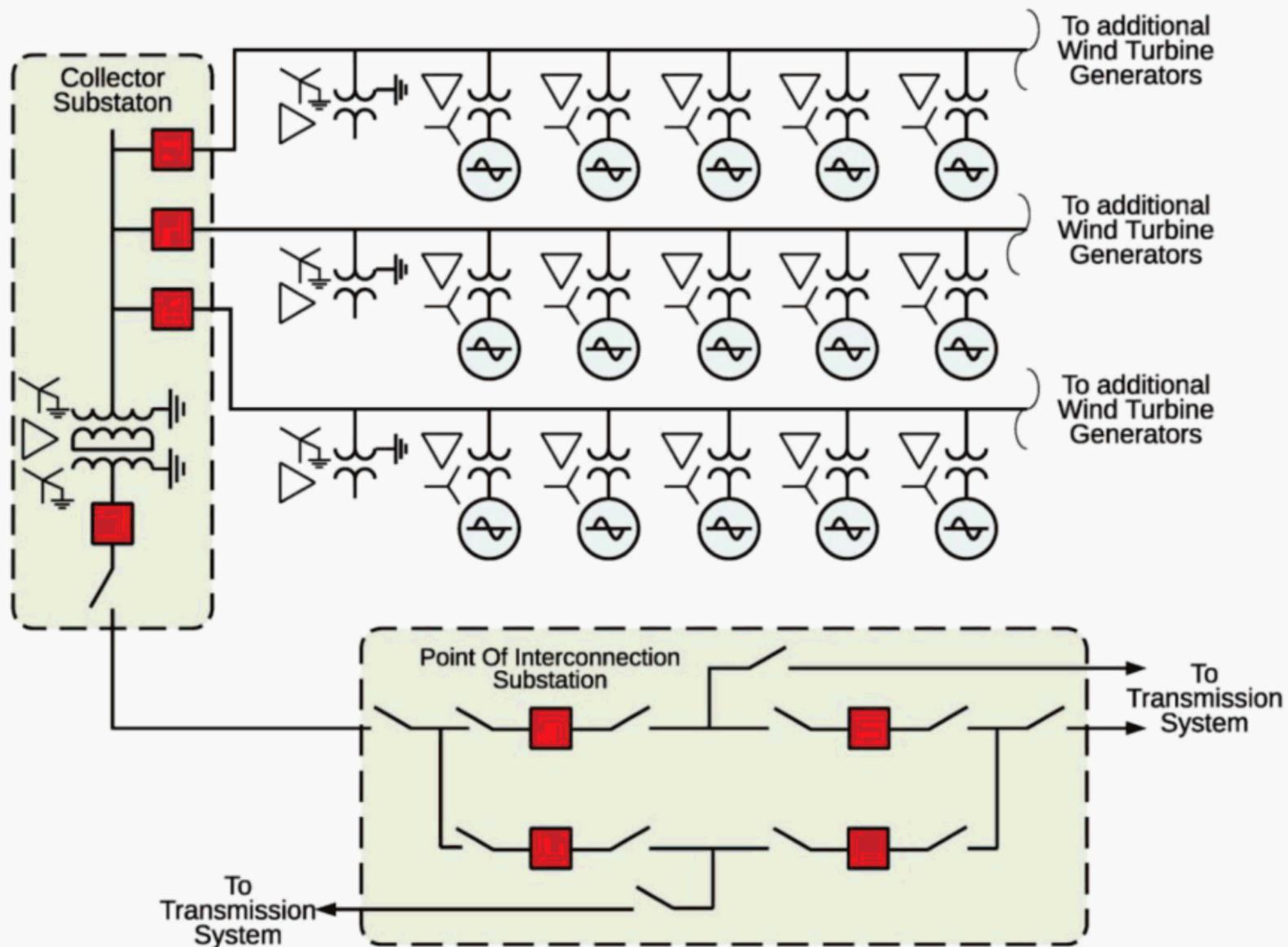


Figure 26—Wind electric plant one-line diagram

Aside from the number of generators, the types of generators may be different. WTGs must be able to tolerate rapid fluctuations in wind speed (turbulence and gusting). The traditional rigid mechanical and electrical coupling of the prime mover and a synchronous generator does not tolerate these fluctuations. As presented in 4.2.2.1.6, five basic types of WTGs can, in some cases with supplemental equipment, tolerate the fluctuations in the wind speed and deliver electrical power in the form that meets the requirements of the transmission system. These generator designs are unique to the wind plants and, except for the Type V WTGs, do not have synchronous generators connected to the AC network. The Type V WTG uses a synchronous generator that is coupled to the wind turbine via a variable ratio transmission. The transmission absorbs the fluctuations in turbine speed. The other four types of WTGs respond differently to faults from the typical synchronous generators.

Although the responses of the different types of WTGs are different, there are some common characteristics. Whereas the initial contribution of a synchronous generator to a close-in fault is in the range of 5 to 6 times the nominal maximum load current output of the generator, the WTGs typically contribute fault current in the 3 to 5 times range. Although the fault current contribution from the synchronous generator decreases with time, the initial current from a WTG deteriorates in a shorter period of time. The fault current from a WTG typically drops from 3 to 5 times nominal current to 1.5 to 2 times in two cycles.

For these two reasons, the relaying installed to detect faults on the transmission system at the point of interconnection to the wind plants needs to be able to respond to wide variations of fault current from the wind plant and respond quickly due to the rapid deterioration of the fault current. Most pilot transmission line relaying systems can meet these requirements, but line current differential protection is preferred for these types of limitations.

For the wind plants to meet the low-voltage ride-through requirement, the plant typically has control systems that dynamically vary the reactive power output of the plant. These types of systems are not unique to wind plants. The transmission owner needs to protect the transmission system and customers' equipment from the abnormal voltages that can occur due to failures or incorrect operation of equipment controlling the reactive power output of the plant.

The point of interest to the transmission owner for the voltage magnitude is at the point of the interconnection substation. A relay is typically installed to monitor the voltage at that location. For out-of-tolerance conditions, the easiest action would be to trip the breaker(s) at the point of the interconnection substation for the tie line to the plant. This type of operation would cause the plant to lose its primary source of station service. Since the wind plant is typically not capable of operating isolated from the transmission system, the loss of the station service typically delays the restoration of the plant after the condition that caused the event has been resolved. An alternative to tripping the breakers at the interconnection is to send a DTT to the collector substation and trip the collector line breakers. This type of operation achieves the desired results while maintaining or restoring the primary station service to the collector substation as soon as the transmission system returns to normal. This type of configuration facilitates restoration of the plant to service.

#### 7.9.2 Solar PV inverter settings considerations

Solar PV inverter output is controlled by a microprocessor controller. The controller typically acts to limit inverter output current under fault conditions. Depending on the manufacturer, the output current could be limited to the range of 1.1 to 1.5 per unit from 1 to 10 cycles. The filtering components of the inverter could contribute up to 2 to 3 per unit fault current for up to a 1/2 cycle. Instantaneous protection elements should be set to account for the initial fault current. Time-delayed elements are difficult to set due to the current-limiting function of the inverter output and the variable nature of the PV. Available fault current relies on the solar availability at the time of the fault, which can vary from zero to maximum output depending on the time of day and weather conditions. Therefore, typical protection such as overcurrent or distance elements cannot be applied as a backup protection. ADTT offers a viable option for tripping generation during faulted conditions.

## 7.10 Interconnection protection validation

The value and importance of validating the interconnection protection, both prior to generation being placed into operation and periodically, should not be overlooked. An examination of the protection scheme pickup settings, timing, functionality, and overall operation as part of commissioning is a prudent final check to help ensure the reliable operation of the interconnection protection during transmission system anomalies.

Tests are utilized in combination with other field checks to verify overall operational integrity. Examples of common tests are secondary injection, instrument transformer ratio tests, polarity tests, load tests, etc., to verify wiring accuracy, pickup setting accuracy, timing accuracy, logic accuracy, and communications as needed.

For more information on protection validation testing, refer to IEEE Std C37.233 [\[B21\]](#).

## Annex A

(informative)

### Bibliography

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