PSRC Working Group C25

Protection of Wind Electric Plants

Power System Relaying and Control Committee
Report of Working Group C25
of the
System Protection Subcommittee

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KEYWORDS

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Harmonic

Protection

Substation

Voltage

Wind

ABBREVIATIONS AND ACRONYMS

DFAG	Doubly Fed Asynchronous Generator (also known as Doubly Fed Induction Generator, DFIG)
DFIG	Doubly Fed Induction Generator (also known as Doubly Fed Asynchronous Generator, DFAG)
EMT	Electro-Magnetic Transient
GSU	Generator Step-up Unit transformer
HV	High Voltage
HVDC	High-Voltage DC
IGE	Induction Generator Effect
LVRT	Low Voltage Ride-Through
MV	Medium Voltage
NERC	North American Electric Reliability Corporation
PCC	Point of Common Coupling
PFCC	Power Factor Correction Capacitors
POI	Point of Interconnection
POTT	Permissive Overreaching Transfer Trip
Pwind	wind generating plant rated Power (MW)
SCIM	Squirrel Cage Induction Machine
SCR	Short-Circuit Ratio
SSCI	Sub-Synchronous Control Interaction
Ssc	System available Short-Circuit MVA
SSR	Sub-Synchronous Resonance
STATCOM	Static Compensator
TOV	Transient Overvoltage
VAR	Volt-Ampere, Reactive
VRT	Voltage Ride Through
VT	Voltage Transformer
WEP	Wind-powered Electricity generating Plant
WTG	Wind Turbine Generator

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1 INTRODUCTION

Working group C25 was given the assignment to write a report to provide guidance on present relay protection and coordination practices at Wind-powered Electricity generating Plants (WEP). This report covers the engineering considerations for the design of the protection systems intended to protect all the elements that form WEPs.

It covers the following protection systems:

- Generator step up transformers
- Collector system feeders
- Grounding transformers
- Collector buses
- Reactors
- Capacitors
- Main station transformers
- Tie lines
- Points of interconnection
- Associated arc flash issues

A WEP is made of many small generators spread over a large area and includes many subsystems that need to be protected. It is important to make sure that all the subsystems are well protected and coordinated to maximize the reliability, security, and dependability of the overall protection and control system.

For those not familiar with the different elements that form a WEP, commonly known as a Wind Farm, this report introduces a description of the different elements comprising a wind farm and how their unique characteristics may be considered to provide a proper design.

This report provides engineering details covering:

- Possible Wind Farm electrical layouts
- Equipment ratings
- System grounding
- Wind electric generator characteristics
- Transformer connections and characteristics
    - Wind turbine generator (WTG)
    - Main substation transformers
- Harmonics and sub-harmonics

- Voltage and frequency control requirements
- Protective relay schemes

For successful application of the information provided in this report, the working group recommends that the reader also become familiar with the guides and publications pertaining to the protection systems described in this report, some of which are provided as references at the end of this document.

1.1 Scope

This report covers protection of generator step up transformers, collector system feeders, grounding transformers, collector substation buses, reactors, capacitors, main station transformers, tie lines, points of interconnection and associated arc flash issues. Although the report addresses coordination with wind turbine generator protective devices and static VAR sources, protection of the wind turbine generators and static VAR sources themselves is not included.

1.2 Purpose

Large WEPs are becoming more prevalent as generation sources on the power system. Construction of these plants is significantly different from traditional large generation stations. A traditional plant may have a relatively small number of large machines – perhaps 2 to 6 generators each with a rating of 100 MW to 500 MW. By comparison, a large modern wind powered generation plant will have a large number of small generators – perhaps 80 to 100 turbines each with a typical rating of 1.5 MW to 3.0 MW. Larger units have become available mostly in offshore wind farms. In a wind powered generation plant, the turbines may be spread over an area as large as 100 square miles (260 square kilometers) or more, where power is collected at medium voltage (usually 34.5 kV) from the individual turbines to a collector substation where the voltage is stepped up to the transmission level for integration into the transmission system.

The performance of the WEP during a fault condition is different from that of a traditional generating station [1]. Therefore, the protection considerations for a large WEP will be different than those of a traditional central station generation plant. This report is intended to provide guidance on relay protection and coordination practices that have been commonly used at terrestrial WEPs to serve as a reference for practitioners working in the design of these plants. Typical design of WEPs is discussed for background information and the relaying practices that have been used with success are presented. Much of the equipment found in a wind powered plant is common to many electric distribution systems – busbars, cables, transformers, and capacitor banks, for example – so references are made to existing standards and guides for protection of that equipment. Any special considerations or cautions particularly related to the application of the equipment in wind electric plants are highlighted in this report. This report does not cover the protection schemes used within the wind turbine generators themselves, or that of other specialty equipment such as STATCOMs. Protection schemes within these types of equipment are designed by their manufacturers and are integral to the equipment.

2 Difference Between Wind Electric Plant Substations and Conventional Distribution Substations

Wind Electric Plants are composed of many wind turbine generators (WTGs) which are connected to a collector substation through a collector system. The collector system is connected to the main substation or Point of Interconnection (POI) where the voltage is stepped up to the transmission voltage level. While WEPs share several common features with conventional utility electric systems, they also have several unique characteristics that are typically considered during the design. Utility substation designs mainly focus on maintaining continuous reliability, whereas economics and unit availability play a more important role in the design of medium-voltage collector systems, collector substations and switchyards, and high-voltage transmission lines/cables of a WEP [2]. In the following subsections, some of the main design characteristics of WEP substations and collector systems are described.

2.1 Collector Feeder Design and Characteristics

A collector system consists of a series of underground cables or overhead lines that deliver power from WTGs to the collector substation. The majority of WEPs are designed with multiple collector feeders/circuits. A collector system may also have a single collector feeder depending on the number of turbines, size of cables, and required system reliability [3]. The design and layout of the WEP collector system depends on several factors such as turbine placement, terrain, reliability, and soil thermal resistivity. The thermal resistivity of the soil has a direct impact on the current carrying capacity of the cables. Additional factors include owner requirements, economics, and expected climatic conditions. However, considerations resulting from the location of turbines and the POI are the more critical factors in the design of the collector system.

The collector substation may be connected directly to the POI. If the POI is located far from the WEP, a transmission line and switchyard[1] may be required in addition to the collector substation. In any case, the collector feeders are connected to one or more substation transformers at the collector substation, where voltage is stepped up to the transmission system voltage. Although collector systems are normally operated

[1] The switchyard may also be referred to as the interconnect substation.

at the highest medium voltage (34.5 kV in North America or 33 kV in Europe), they are sometimes designed to operate at a voltage as low as 12 kV depending on the available substation voltages. The reason is that the existing low-voltage equipment/infrastructure may be too costly to change or reconfigure.

The collector feeder is commonly of underground type but could be of overhead construction depending on the thermal resistivity of the soil, grounding requirements, economic aspects, operation and maintenance requirements, local landowner requirements, and system efficiency. Collector systems may consist of a combination of overhead transmission lines (for connecting the collector substation to transmission lines) and trenched underground or submarine cable systems (for the collector system). The collector cable and/or conductors are evaluated to optimize losses, voltage drop, system reliability, and maintenance criteria [9][3], [4]. It is also noted that the number of WTGs connected to a collector feeder is determined based on the conductor ampacity. The rating of the step-up transformer at the collector substation is based on the number of WTGs on the system of collector feeders.

Collector systems of large WEPs normally have a radial configuration where turbines are interconnected in a daisy-chain style, moving from the collector substation to the farthest turbine. Figure 1 shows a typical collector feeder. As seen in this figure, collector feeders may also have branch strings connected by junction boxes. The junction boxes, in turn, have separable connectors (or elbows) that allow isolation of a feeder string to enable continuous operation of the remaining connected turbines while maintenance or repair work is being performed.

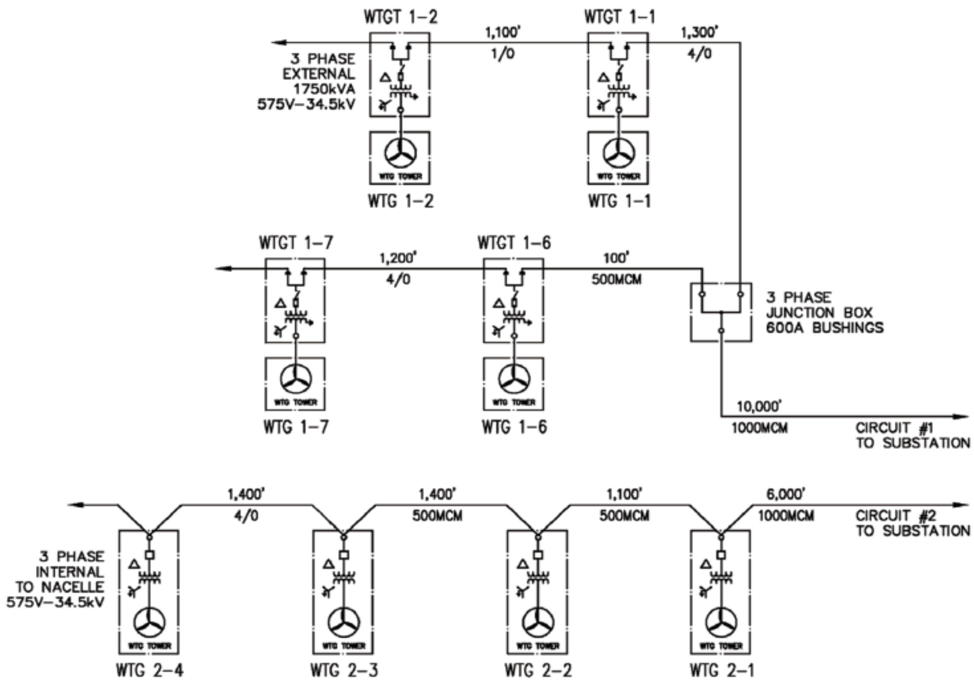


Figure 1: A typical collector feeder [10]

Wind turbine generators are often interfaced with the collector feeder through a generator step-up (GSU) transformer that increases the generator voltage (typically 690 V or lower for WTGs smaller than 3 MW, and 3.3 kV or 6 kV for larger generators) to the collector system voltage (up to 34.5 kV). Several studies are normally performed on collector systems to identify the effects of the WTGs on the power system. Industrial and commercial power systems standards are sometimes used for the execution of such interconnection and collector system studies [9].

2.2 Wind Electric Plant Substation Arrangements

The planning and design of the WEP substation and switchyard can have some flexibility based on the required reliability, operability, and maintainability. Wind electric plant substation designs typically consist of a collector (medium-voltage bus) and interconnection (high-voltage bus) configuration. These two systems are connected through wye-wye (with buried delta), delta-wye, or even wye-delta transformers as shown in Figure 2. The wye-wye (with buried delta) transformer connection shown in Figure 2(b) is commonly used [10]. Figure 2(c) indicates that a substation transformer with the delta connection on the collector side requires some other means to provide adequate grounding (e.g., a grounding transformer connected to the medium-voltage side).

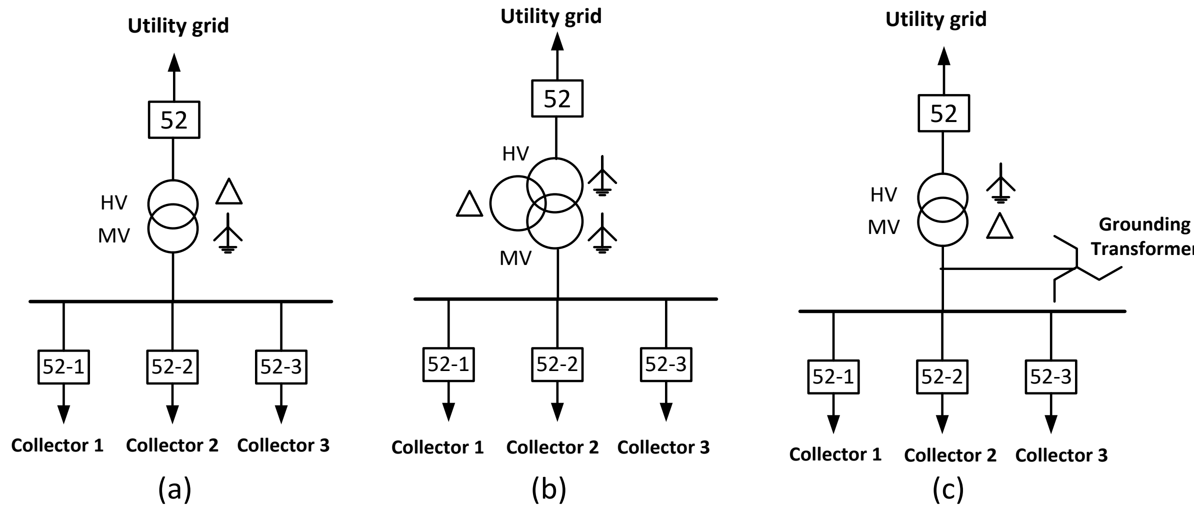


Figure 2: Common collector substation transformer configurations (a) delta–wye grounded, (b) wye grounded–wye grounded with buried delta, and (c) wye grounded–delta winding configurations

Collector substations for WEPs typically use an open-air bus design with single bus or sectionalized bus arrangements [2]. Figure 3 illustrates common medium-voltage (MV) bus substation configurations in WEPs. The single-bus design (Figure 3(a)) is simple and very cost effective, but is a single point of failure and may be less reliable than some other (more costly) alternatives. The sectionalized bus configuration (Figure 3(b)) improves system reliability and availability when one of the station transformers is out of service, albeit at a higher price. One may also need to evaluate the potential improvement in energy production against the increased costs to determine the economic benefits offered by the second transformer in a sectionalized bus configuration [11]. In large plants, the use of multiple smaller transformers and sectionalized buses instead of a single larger transformer will result in lower short-circuit currents, provided the transformers are not operated in parallel. Reduced short circuit current may be desirable for reduced stress on equipment and reduced arc flash hazard in case of a fault. The ideal collector substation location is within a central area of the WEP to optimize the cost of collector lines and the efficiency of the plant. In practice the final location of the collector substation may depend on other factors, such as soil conditions, excavation requirements, land constraints, and the location of the POI.

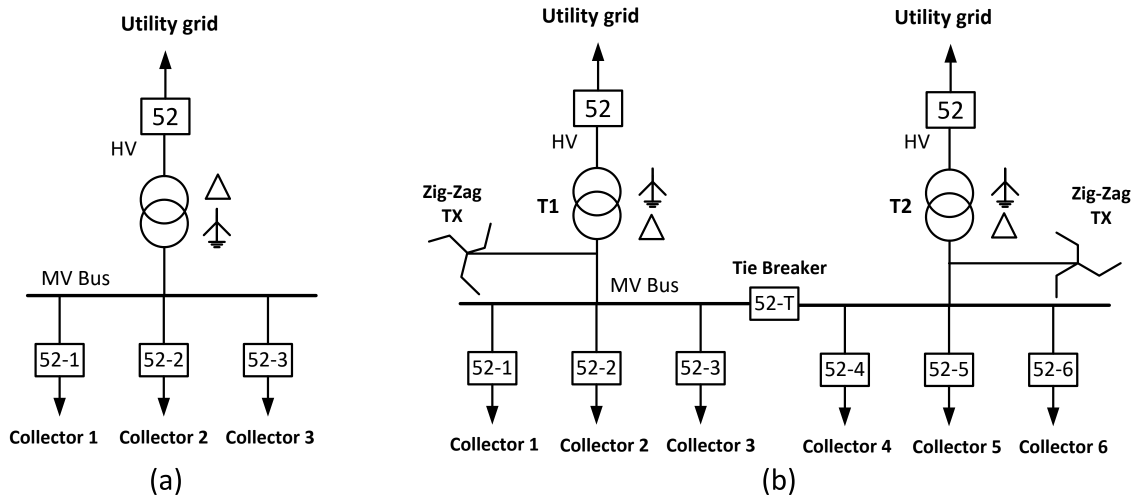


Figure 3: Common collector substation arrangements (MV bus configurations) for WEPs: (a) single-bus configuration and (b) sectionalized-bus configuration

While the MV buses of WEPs are primarily of the single and sectionalized-bus type, the high-voltage (HV) buses could be of five common configurations: single, sectionalized, ring, breaker-and-a-half, and double-breaker double-bus. Figure 4 shows these five configurations. More details about these five arrangements can be found in IEEE Std. 666 [11]which discusses various bus configurations for generating stations. Table 1 compares the cost and reliability of each bus configuration. The table shows that the double breaker-double bus and breaker-and-a-half configurations have the highest reliability, albeit at the highest cost. The bus configurations used in the MV bus design have relatively low reliability as compared to the more complicated HV bus configurations.

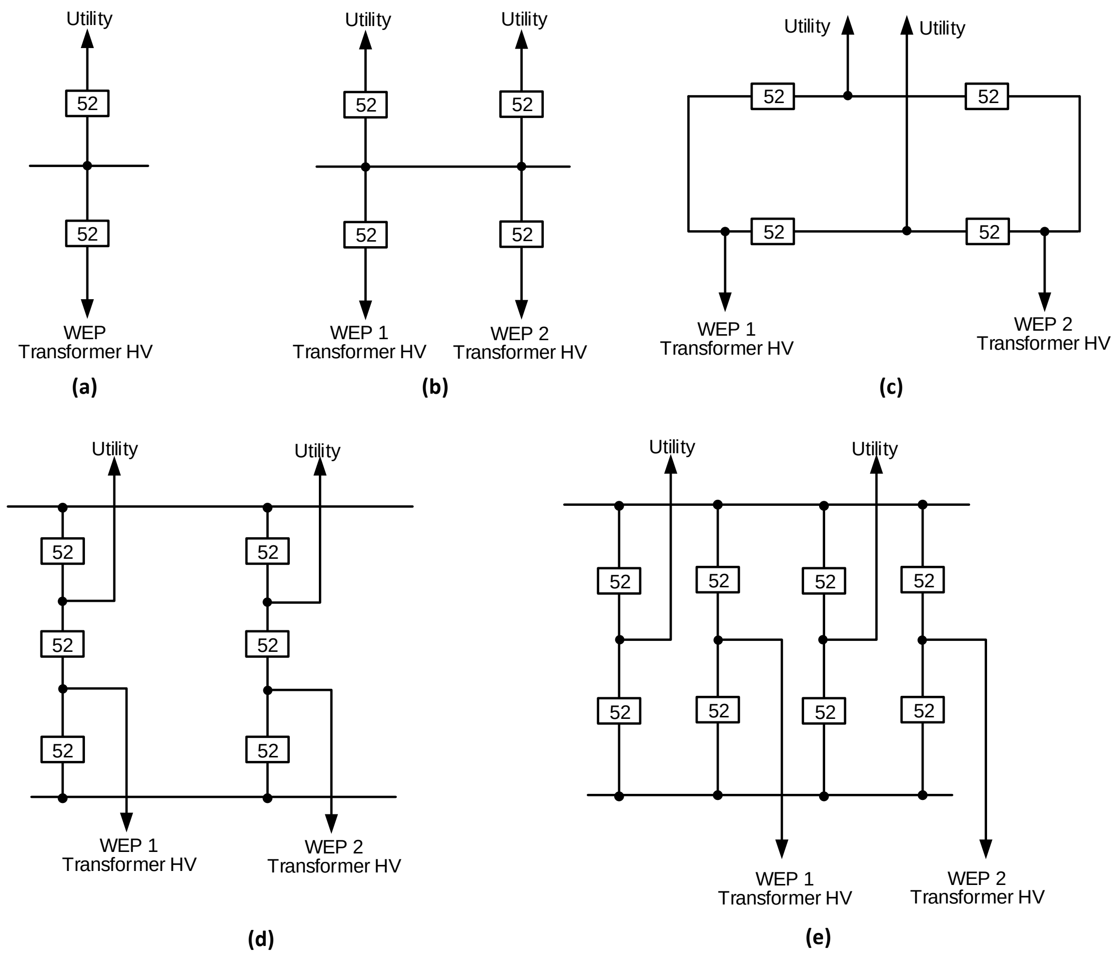


Figure 4: Different HV bus configurations: (a) single bus configuration, (b) sectionalize bus configuration, (c) ring configuration, (d) Breaker-and-a-Half configuration, and Double Bus–Double Breaker configuration

Table 1: Cost/Reliability Comparison for Different Bus Configurations [9]

Reference	Bus Configuration	Relative Cost	Relative Reliability	Application	
				HV	MV
Fig. 4(a)	Single	46.7%	Low	X	X
Fig. 4(b)	Sectionalized	57.0%	Low	X	X

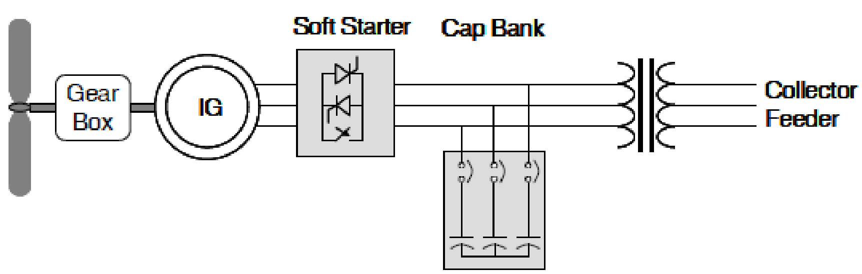
Fig. 4(c)	Ring	53.3%	Medium	X	
Fig. 4(d)	Breaker-and-a-Half	73.8%	High	X	
Fig. 4(e)	Double Bus–Double Breaker	100%	High	X	

2.3 Wind Electric Generator Characteristics

Wind turbines can be classified by their mechanical power control as stall regulated or pitched regulated. According to speed control, wind turbines can be divided into fixed speed (Type 1), limited variable speed (Type 2), variable speed with partial power electronic conversion (Type 3), variable speed with full power electronic conversion (Type 4), and variable speed with mechanical speed/torque converter (Type 5). These different types are shown in Figures 5 to 9. [9] IEEE PES PSRC Working Group C17 produced a report [1] about WTGs and their respective response to faults with respect to each Type of WTG. A brief summary of the characteristics of the five WTG types is provided below, based in part on the C17 Working Group report [1] and [16].

2.3.1 Type 1

A typical Type 1 WTG is a Squirrel Cage Induction Machine (SCIM). This induction machine is typically connected to the collector system through a step-up transformer and soft starter[2]. Power factor correction capacitors (PFCC) are typically included and divided into different steps or stages that are switched in or out during differing operating speeds of the turbine shaft. The speed of the turbine shaft is controlled to a near constant value (typically 2-3% faster than the grid's synchronous frequency). Therefore, the WTG generates real power when the turbine shaft rotates faster than the electrical grid frequency.



[2] The main function of the soft starter is to enable synchronization to the grid without massive inrush currents on the generator.

Figure 5: Typical configuration of a Type 1 WTG

2.3.2 Type 2

A typical Type 2 WTG is an induction machine having an external resistance inserted into the rotor circuit to provide operation over a wider range of slips when compared to a Type 1 induction machine. This induction machine is typically connected to the collector system through a step-up transformer and soft starter. Power factor correction capacitors (PFCC) are, again, typically included and divided into different steps or stages that are switched in or out during differing operating speeds of the turbine shaft. Like the Type 1 WTG, the speed of the turbine shaft of the Type 2 WTG is controlled to a near constant value (typically up to 10% faster than the grid's synchronous frequency).

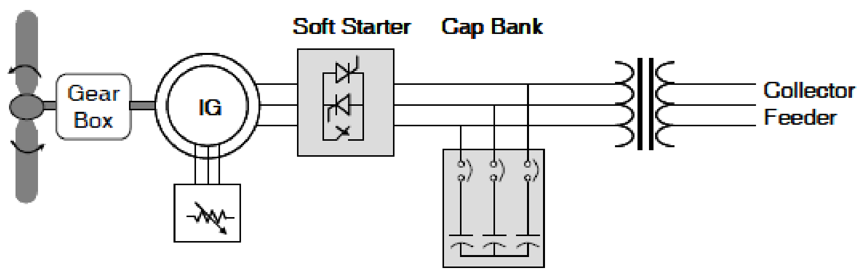


Figure 6: Typical configuration of a Type 2 WTG

2.3.3 Type 3

A typical Type 3 WTG is also called the Doubly Fed Induction Generator (DFIG) or Doubly Fed Asynchronous Generator (DFAG). An AC-DC-AC converter provides variable frequency ac excitation to the rotor circuit to enable the WTG to operate at variable speeds (typically ± 30% of the synchronous speed), and to provide reactive power control and ac voltage regulation capabilities. The power factor of a Type 3 WTG typically ranges from 0.90 (lagging capacitive) to 1.0 (unity) to 0.9 (leading inductive) at rated active power generation.

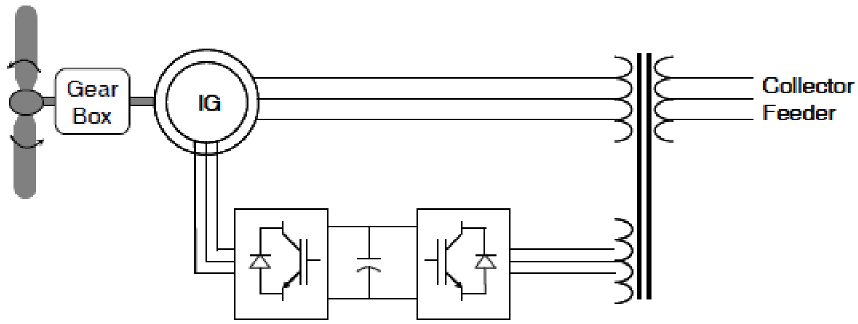


Figure 7: Typical configuration of a Type 3 WTG

2.3.4 Type 4

A typical Type 4 WTG is composed of an electrical machine interconnected to the collector system through a full-scale back-to-back (AC-DC-AC) frequency converter. The electrical machine of this wind turbine type may use a synchronous machine excited either by permanent magnets or by an asynchronous machine. In contrast to Types 1-3, the generator of a Type 4 WTG is completely decoupled from the grid, so a gearbox may not be required. If an asynchronous generator is used, a gearbox is often included in the design. The electrical output of a Type 4 WTG is completely defined by power electronics, that is, the full-scale converter, and not the inherent behavior of the generator. This design allows Type 4 WTGs to rotate at an optimal aerodynamic speed providing extreme flexibility in generation in combination with excellent grid integration characteristics such as flexible reactive power capabilities and a wide voltage and frequency operating range. Like the Type 3, the power factor of a Type 4 WTG typically ranges from 0.90 (lagging capacitive) to 1.0 (unity) to - 0.9 (leading inductive) at rated active power generation.

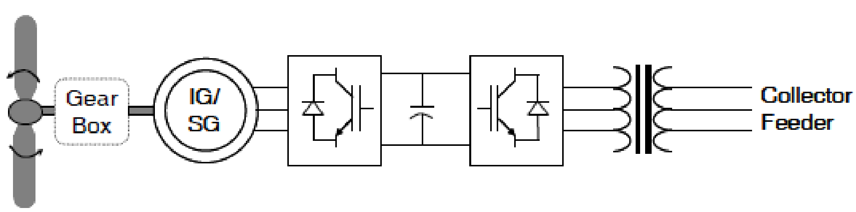


Figure 8: Typical configuration of a Type 4 WTG

2.3.5 Type 5

A typical Type 5 WTG consists of a WTG variable-speed drive train connected to a speed/torque converter coupled with a synchronous generator. A Type 5 WTG exhibits typical synchronous generator characteristics and behavior during faults.

Therefore, generator contributions to faults can be calculated from the generator machine constants provided from the respective generator manufacturers.

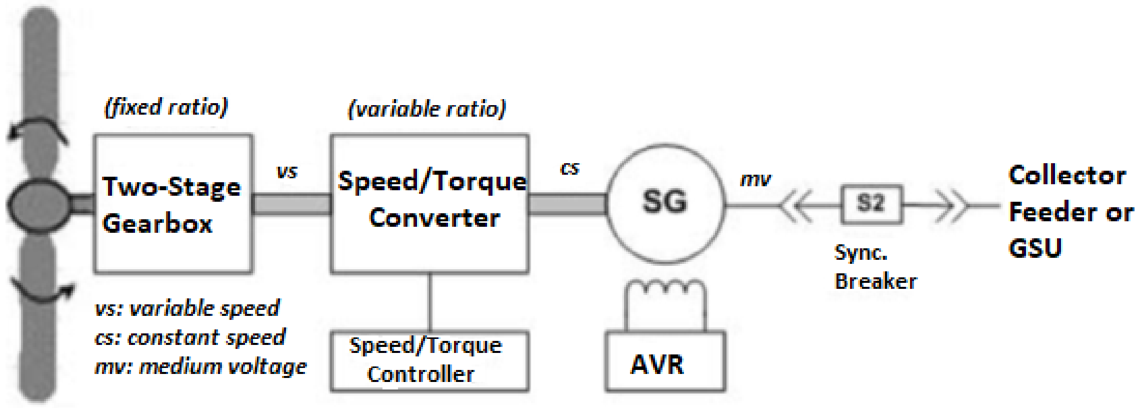


Figure 9: Typical configuration of a Type 5 WTG

2.4 Fault Currents and Equipment Ratings

To choose the ratings of equipment in the substation of a generating plant, maximum fault currents need to be calculated. For selection and settings of protective devices both maximum and minimum fault currents need to be calculated. For conventional generating stations, short circuit models of synchronous generators are well known, and the currents can be found using phasor domain short circuit programs that model the generators as Thevenin models with appropriate impedances for sub-transient, transient, or steady state time frames. The worst-case dc offset is also known and can be worked into the fault current calculations.

For wind electric plants, the fault currents for a given fault on the collector circuit or at the point of interconnection will depend on the type of WTGs employed in the plant. While Type 1 and 2 WTGs can usually be represented by a Thevenin model, Type 3 and 4 exhibit unconventional behavior. The fault contribution from these machines depends heavily on the proprietary controls implemented in their converters. A Type 3 machine can switch back and forth between crowbarred mode and controlled mode, whereas a Type 4 is fully controlled, limiting fault currents to values comparable with load currents (110% of load current, for example) within approximately two cycles. Phasor domain short-circuit programs can model these machines as a voltage-dependent current source. An iterative method of solution can then be used to account for the nonlinear fault response caused by the converter controls. Additional information on WTG modeling is available in the PSRC Working Group C24 report titled, “Modification of Commercial Fault Calculation Programs for Wind Turbine Generators” [33].

In the absence of precise fault models, the maximum fault current from a Type 3 machine can be calculated assuming it is crowbarred, which enables it to be modeled as a Type 2 machine. For a Type 4, the maximum fault current will have to be provided by the manufacturer for uncontrolled as well as controlled modes. Conversely, the minimum fault contribution for Type 3 and 4 machines will have to be obtained from the manufacturer. The minimum fault current will depend on the number of WTG units in operation at the time of fault, and the fault location.

An important feature of the fault responses of Type 1, 2 and 3 (crowbarred) WTGs is the amount of dc offset in the fault current. Studies show that the dc offset in combination with ac decrement can cause the resulting ac current to be without a zero-crossing for several cycles [1]. However, studies also show that a very small value of resistance in the fault current path can result in very quick decay of the dc component [5]. Due to the resistance of cables, pad mounted transformers, and the resistance of the arc between circuit breaker contacts, in practice the dc offset does not pose a serious challenge to the operation of circuit breakers.

2.5 System Grounding

Wind Electric Plant system grounding is an important consideration in plant design because it directly leads to the determination of protection schemes that can be applied to maximize the safe and reliable operation of this generating asset. Moreover, the different types of wind turbines (Type 1, Type 2, Type 3, Type 4, or Type 5) have different characteristics that cause individual WTG types to contribute differently under various fault conditions. For example, for many short-circuit studies, Type 1 and Type 2[3] generators can be modeled as an equivalent Thevenin impedance such that they can contribute positive, negative, and zero sequence current to a fault. The sequence current contributions from Type 3 and Type 4 generators are a function of the electrical characteristics of their converters. Both can contribute positive and negative sequence current, but a Type 4 generator does not produce zero sequence current. Type 5 generators have the same characteristics as a synchronous generator. Therefore, the WTG characteristics are an important consideration when applying the protection scheme design for both the generator and its associated WTG step-up transformer.

[3] Depending on the study and the WTG’s crowbar system, replacing Type 2 WTGs with a Thevenin equivalent may not be possible.

The secondary (low voltage or generator) side of the WTG step-up transformer is typically connected in grounded wye to provide a stable reference point for the system phase to neutral voltages to enhance equipment and personnel safety. The grounded wye connection also causes the majority (or all) of the current for a ground fault on the WTG and low voltage bus to come from the GSU transformer where the ground fault current magnitude is usually large enough to operate simple phase and ground overcurrent or fuse protection equipment. A primary reference for the application of grounding techniques in North America is IEEE Standard 142-2007: IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (also known as the "IEEE Green Book"), and subsequent approved updates/revisions of this standard[4]. According to this standard, solid grounding is generally recommended for the following:

a) Low-voltage systems (600 V and below) where automatic isolation of a faulted circuit can be tolerated or where capability is lacking to isolate a ground fault in a high-resistance grounded system.
b) Medium- or high-voltage systems (above 15 kV) to permit the use of equipment with insulation levels to ground rated for less than line to line voltage.
c) Medium- or high-voltage applications where higher ground fault current magnitudes are required to provide selective ground-fault detection on lengthy distribution feeders.

Bullet b) from the IEEE 142 excerpt above refers to the use of equipment with phase to ground insulation levels on systems that are "effectively grounded". Once this determination is made, the designer typically evaluates the system to verify that for all foreseeable conditions, including fault conditions, the system remains "effectively grounded". For example, the zero-sequence network impedance of a Type 4 WTG is effectively infinite. Therefore, utilization of a wye-ground to wye-ground GSU for interconnection of a Type 4 unit to the collector system will not maintain an effectively grounded collector system when a ground fault is present, and the main substation feeder breaker has tripped to clear the fault. After the breaker opens, the WTGs may continue to energize the collector feeder until it shuts down from loss of load. Such a condition can lead to the development of transient overvoltage (TOV) on the collector circuit, if other methods of remediation are not undertaken.

Many WTG step-up transformers supplying underground collector feeders are connected in grounded wye on the WTG side and delta on the collector feeder side of the transformer. In that case, a permanent ground fault on the collector feeder may

[4] At the time of this report, IEEE Standard 3003.1-2019 is expected to replace IEEE Standard 142-2007 Grounding of Industrial and Commercial Power Systems.

also cause a TOV condition after the main collector feeder trips and the WTGs are shutting down. Utilization of a properly sized ground bank on the collector feeder circuit, $3E_0/3V_0$ protection, grounding breakers, or direct transfer trip of the generation generally provides effective means of such control.

2.6 Transformer Connections and Characteristics

The section discusses the considerations associated with various interconnection transformer configurations.

2.6.1 Wind Turbine Generator Transformers

Most WTGs produce AC power at 690 V or lower for generators smaller than 3 MW, and 3.3 or 6 kV for larger generators. A collector system network consolidates the power produced by the individual WTGs in the wind electric plant. This collector system network is typically operated at 33 - 34.5 kV, although for smaller plants, the collector system network might be operated at 12 kV. In either case, transformers will be required between the WTG and the collector system. The WTG is typically wye connected but ungrounded. For this reason, the WTG transformers are normally configured to provide a ground reference for the low voltage system. It is very common to use delta - wye transformers with the wye on the low voltage side. In these cases, the neutral on the wye may be connected to earth. Although this is a common configuration for the WTG transformers, wye - wye transformers have also been used, with the neutral on one or both sides of the transformers connected to earth.

The WTG transformers are typically in one of two locations: The WTG nacelle or on the ground next to the tower. Many of the larger WTGs will have the transformers located in the nacelle. The nacelle is the housing on the top of the tower which contains the generator and inverters. This design will reduce the losses and the size of the cable needed for the run down the tower. In this design, a medium voltage breaker is typically installed to provide protection for the transformer. The other configuration, which is typically used for WTGs smaller than 3 MW, has the transformer on the ground next to the tower. In this design, fuses are typically installed to provide the transformer protection.

2.6.2 Main Substation Transformers

For most transmission network interconnections to wind electric plants, the collector network voltage is not the voltage of the transmission network, so another transformation is required. Since the WTGs and their transformers typically do not provide ground references to the MV network, to be able to use equipment that is designed for an effectively grounded system it is necessary for the main substation transformer to provide a ground reference to the MV system. Depending on the transmission network connected to the plant, the transmission provider may require that the main substation transformer also be a ground reference to the transmission network. If a ground reference is not required by the transmission provider, then a delta - wye grounded transformer with the wye on the MV side will be an adequate transformer. If it is a requirement that the main substation transformer also be a ground reference to the transmission network, then there are a couple of options. The most commonly used transformer configuration is a wye - wye transformer with a delta tertiary winding. Both HV and MV wye neutrals are connected to the earth. This type of configuration is shown in Figure 10. The other option is to use a delta - wye transformer in conjunction with a grounding transformer. The grounding transformer would be connected on the transmission network side where the main transformer delta winding is connected. The grounding transformer can be a two-winding wye - delta transformer or a zig zag grounding transformer.

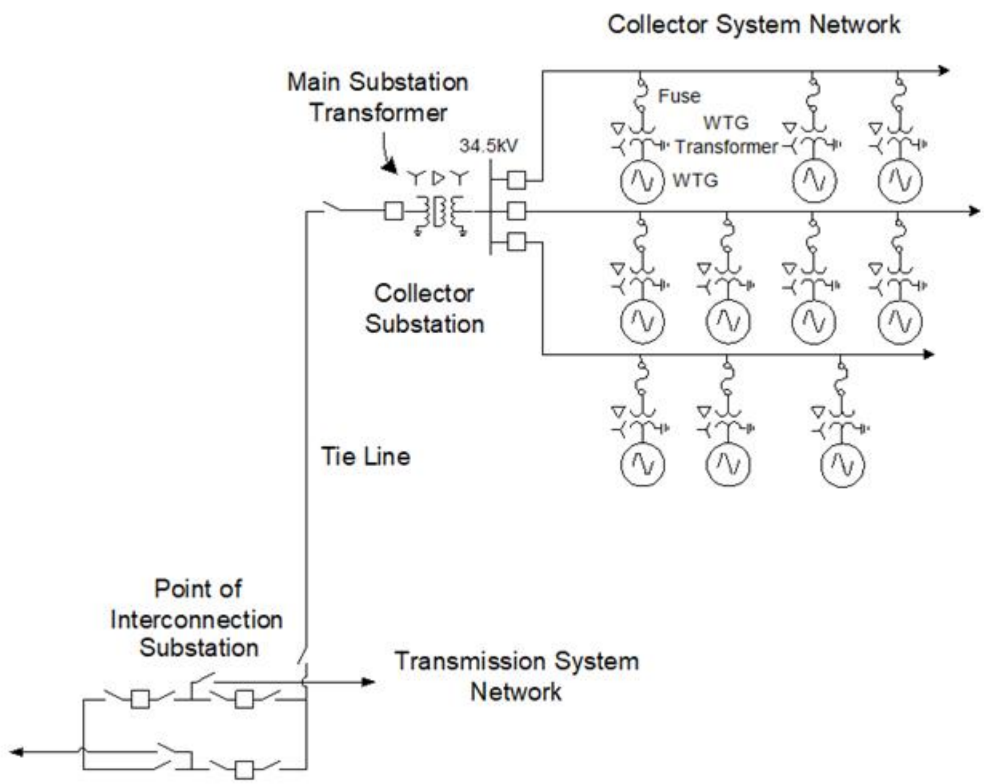


Figure 10: Simplified One Line Diagram of Wind Electric Plant

2.7 Harmonics and Sub-harmonics

The harmonics due to wind plants will depend on converter topology, applied harmonic filters, and short-circuit current at the Point of Common Coupling (PCC). Even harmonics in wind generation can arise due to unsymmetrical half waves and may appear at fast load changes. Sub-harmonics are spectral components whose frequencies are lower than the fundamental power frequency. Sub-harmonics can be produced due to periodical switching with variable frequency or arise due to interaction between wind generation and series compensated transmission lines. Sub-harmonics can also be created due to various phenomena such as induction generator effects, control interactions, torsional interactions, and torque amplification.

When a series capacitor offsets partial system reactance, the system will have a natural frequency less than the system frequency, which is referred to as sub-harmonic. The generator armature sub-harmonic currents produce magnetic fields with the natural frequency, which induce currents in the generator rotor. This rotor current frequency will be the difference between the fundamental frequency and the natural frequency. This new added rotor current frequency will cause sub-synchronous armature voltages that may enhance the sub-synchronous currents and may cause generator self-excitation. Because the rotor turns faster than the sub-harmonic armature currents, a slip is created to simulate an induction machine. This is called the Induction Generator Effect (IGE), where the rotor resistance of the machine presents itself as a negative resistance with respect to sub-synchronous frequencies. The system presents itself as a positive resistance at the system natural frequencies, but if the negative resistance is greater than the positive resistance, then sub-synchronous currents will be sustained and possibly amplified, thus causing serious voltage and current oscillations. Generally, the greater the number of turbines, the lower the magnitude of the harmonics and sub-harmonics, especially of the lower order.

The energy portfolios of energy providers around the world are increasingly comprised of renewable energy sources like wind and solar. As the size of these individual energy facilities increases, the rated capacity of the connected transmission systems will also increase. The transmission expansions to wind electric plants are often radial in nature, and to maximize return on investment, they are usually sized to carry no more power than is required for a wind power facility [8].

Series capacitor compensation in AC transmission systems is an economical means to increase the load carrying capability of a line, to control load sharing among parallel lines, and to enhance transient stability [14]. However, capacitors in series with transmission lines may cause sub-synchronous resonance (SSR) with generators near a series capacitor. Sub-Synchronous Resonance occurs when the mechanical mass of the generator shaft resonates with the effective impedance of the system, which can lead to turbine-generator shaft failure and electrical instability at oscillation frequencies lower than the normal system frequency. Therefore, it is important to fully understand the effects of SSR and to analyze them when planning series capacitor compensation in power systems.

It is important that interconnection studies for any generator or power electronic equipment in the vicinity of a series capacitor can account for system configurations that may give rise to sub-synchronous oscillations. Any generation or power electronic equipment connected in a radial series-compensated configuration is particularly susceptible to the phenomena of Sub-Synchronous Control Interaction (SSCI). It is also important to study these phenomena whenever series compensation is being added to a transmission system. Sub-Synchronous Control Interaction is a relatively new problem which has been observed between power electronic devices, such as an HVDC link, a static VAR compensator, or a wind turbine and a series compensated system [13]. A typical SSCI event is a condition where the wind turbines/controls interact with nearby series capacitors, resulting in un-damped/fast growing oscillations. This is a widespread and serious problem, affecting turbines from most major manufacturers. Furthermore, standard transient stability studies performed as per the interconnection standards do not show this problem because they use fundamental frequency phasor solutions. The negative damping observed in the SSCI phenomena is largely due to the wind turbine rotor side current controller in the Type 3 topology. In all cases of potential SSCI, it is highly recommended that detailed electromagnetic transient models of the turbine be obtained directly from the manufacturer. Modern power system study tools can integrate code from the actual WTG controls into simulation models such that excellent predictions of SSCI phenomena may be produced. Increased awareness of SSCI is critical, along with backup protection schemes capable of preventing equipment damage in the event of SSCI.

To evaluate wind and transmission projects for possible sub-synchronous interaction issues when used in conjunction with series compensated transmission systems, it is helpful to consider the following recommendations:

- When possible, use detailed EMT models of the WTG unit obtained directly from the manufacturer during the project planning stages to provide a complete understanding of WTG performance, and to evaluate potential problems. The best models directly use the real code from the actual WTG controller hardware.
- Wind turbine manufacturers are encouraged to aggressively research SSCI and see if improvements can be made in their turbine controls.

- It is important for wind developers to be aware of potential problems of WTGs operating near series compensated lines and to be aware of the potential complexities this introduces.
- Transmission providers are encouraged to update their interconnection standards to require EMT/SSCI analysis to be performed when WTGs are connected near series compensated lines, and to plan for proper protection systems to be in place.
- Transmission planners are encouraged to include the additional costs for SSCI related problems when comparing lines with series capacitors to higher voltage AC lines, or DC solutions.
- It is important to perform sufficient studies that identify locations that are susceptible to isolation of generation or power electronic equipment with series compensated transmission lines. In addition, integration of wind farms into systems where the short circuit ratio (SCR) is low (<5) may be identified as potential locations for SSR (SCR = Ssc / Pwind).

Appropriate transmission system design enhancements need to be considered when studying integration of large-scale wind farms. Some measures that may be considered include:

- Limiting series compensation to safe levels.
- Installing thyristor-controlled series capacitors.
- Installing SSR blocking filters.
- Installing additional protection systems to detect SSR and take corrective action.
- Installing additional protection systems to avoid SSR based on system topology.
- Exploring alternatives to increase system strength.
- Exploring modifications to turbine control technology.

2.8 Voltage and Frequency Control Requirements

The voltage ride-through (VRT) capabilities of WTGs vary based on requirements specified by various regulating authorities. For example, regulating authorities in the United States require wind plants to ride-through a three-phase fault on the high side of the substation transformer for up to 9 cycles, depending on the primary fault clearing time of the circuit breakers at the location (Federal Energy Regulatory Commission Order 661-A [19]). Additional regulating authority requirements may define voltage and frequency protective relay settings to maximize a generating unit's ability to remain connected during a voltage or frequency excursion. It is important for the protection engineer to verify that all proposed relay settings comply with any standards established by area regulating authorities.

Some of the Type 1 WTGs have limited VRT capability and may require a central reactive power compensation system to meet wind power plant VRT capability. Many of the Types 2, 3, and 4 WTGs have certain VRT capabilities. None of WTG Types 1-4 have frequency control capability, but some WTG vendors can provide data on the frequency ride-through capability of their machines. The Type 5 WTG is similar to that of a standard grid-connected synchronous generator and therefore has both voltage and frequency control and ride-through capability.

3 Typical Protective Relay Schemes at Wind Electric Power Plant Substations

3.1 Collector Feeder Protection

Collector feeder circuit operation exhibits both radial and network characteristics. When the WTGs are off-line, they draw only relatively low load current required by their station auxiliary equipment (lights, heaters, turbine gear motors, etc.). This station service current for the WTGs flows radially from the Collector Substation to the WTGs on the line, and system fault current flows exclusively from the Collector Substation to the fault location on the line or at a WTG. When the WTGs are on-line, their collective output current flows from the WTGs to the Collector Substation, and with multiple generation sources, the collector feeder operates as a network. If a fault occurs on the line or at a WTG, most of the fault current comes from the Collector Substation, but a small component of the total fault current does come from any WTGs that are online at the time of the fault. Therefore, relay protection schemes that are commonly applied for either radial or network distribution circuits may be considered. Non-directional overcurrent protection schemes have traditionally been applied for radial distribution line protection.

Directional over-current protection schemes have traditionally been applied for protection of network or looped circuits, as well as directional distance relay protection schemes. Ideally, the protection scheme applied at the main feeder breaker at a WEP station provides primary protection for the collector feeder and backup protection for the step-up transformer at each WTG location. The inverse time-current characteristic of a time overcurrent relay can be selected to coordinate with the thermal damage curve of a line conductor or transformer as well as with overcurrent protective devices such as transformer fuses. Directional distance relays can be set to provide excellent primary feeder protection by utilizing two or more “zones” of collector feeder protection using a fixed impedance reach and definite delay setting for each zone. However, to also provide backup protection for the WTG transformers at more than two or three values of fault current, a multiplicity of distance zones and time delays would be required. Therefore, non-directional and directional overcurrent schemes are typically applied for collector feeder protection.

The response of the collector feeder relays is coordinated with other transmission-side overcurrent relays and feeder side fuses or relayed fault Interrupters protecting the generator step-up transformers. In some cases, it may be preferable to coordinate the collector feeder relays with the protective device on the low voltage side of the WTG GSU transformer. This approach can provide faster clearing times or higher sensitivity on the feeder, which may reduce cable costs, or reduce the hazard associated with arc flash. In this case, directional overcurrent relays can usually be applied and set with enough sensitivity to detect a fault on the low voltage side of the WTG GSU transformer. Additionally, a mix of directional and non-directional overcurrent relays may be used to discriminate between faults on the transmission system and faults on the feeder circuit.

Normal current flow at the wind plant is from the feeder towards the transmission grid, so any significant current towards the generators on the feeder (that is, current greater than auxiliary loads when the generators are not running or inrush current when energizing the feeder) would be indicative of a fault. Fault currents with direction toward the feeder are normally cleared promptly to minimize equipment damage and personnel hazards. For faults with direction toward the transmission system, the collector feeder protection may operate in a backup mode. In this case, the feeder protection relay's response may be delayed to allow the primary protection schemes for the transformer or the transmission line to operate first, but still be fast enough to prevent damage to the collector feeder and transmission system equipment if those primary protection schemes do not operate as intended.

3.1.1 Overcurrent Protection and Coordination with WTG Transformer Protective Devices

Overcurrent protection of collector feeder circuits typically include the application of both instantaneous and time delay phase and ground overcurrent elements. Negative sequence overcurrent elements can also be applied for additional protection and to satisfy specialized device coordination requirements. In many cases, simple non-directional overcurrent protection can be used to provide collector feeder protection. However, collector feeders consisting of long cable runs between many high-output wind turbine generators (WTGs) may require directional overcurrent elements to provide adequate protection.

3.1.1.1 Non-directional Overcurrent Protection

Non-directional overcurrent protection can be applied to collector feeders for which the fault current contribution from the WEP substation bus is much higher than the combined fault or load current contribution from the WTGs on the collector feeder circuit to be protected. In such cases, the current pickup level of the phase time overcurrent (51P) element or relay at the substation collector feeder breaker can be set at some factor times the combined output current capability of the WTGs. The selection of the 51P current pickup level may be governed by requirements established by various regulating authorities. The curve type and time dial are then selected to coordinate with the expulsion fuse on the medium voltage side of the WTG step-up transformer.

For example, on a collector feeder in the United States consisting of eight 3.06 MW at 0.9 power factor wind turbine generators, the full load current I_{FLA} of all 8 generators at the 34.5 kV main feeder breaker is:

$$I_{FLA} = \frac{8 \times 3.06MW \times 1000}{0.9 \times 1.732 \times 34.5kV} = 455\ Amp\ (34.5kV\ side)$$

Since the 51P relay is non-directional, the area regulating authority requires its trip current setting to be greater than or equal to 1.3 x I_{FLA} for asynchronous generators and inverters (North American Electric Reliability Corporation Standard PRC-025: Generator Relay Loadability [20]). Moreover, since the 51P and its feeder breaker are on the 34.5 kV side of the 138/34.5 kV Main Substation GSU transformer, PRC-025 Option 5a requires the setting to be calculated for a generator bus voltage corresponding to 1.0 per-unit of the high-side nominal voltage times the turns ratio of the GSU transformer. If the turns ratio of the GSU is 34.5 kV/139.725 kV, then the corresponding generator bus voltage V_{gen} for a 1.0 per-unit nominal voltage of 138 kV is:

$$V_{gen} = \frac{1.0pu \times 138kV \times 34.5kV}{139.75kV} = 34.07kV$$

Therefore, the 51P pickup setting (51PP) can be made be greater than or equal to:

$$51PP = \frac{1.3 \times 8 \times 3.06MW \times 1000}{0.9 \times 1.732 \times 34.07kV} = 599Amp\ (primary)$$

If the CT ratio on the feeder is 1200:5, then the current setting for the 51P tripping element can be 2.5 A, secondary = 600 A, primary.

Wind turbine generator step-up transformers may be equipped with an expulsion fuse in series with a current limiting fuse on each phase of the high voltage side of the transformer. A low-voltage breaker equipped with an overcurrent trip device may be applied to protect the low voltage cables and auxiliary equipment. The WTG vendor usually sizes both the transformer high-side fuses and the low voltage breaker and applies trip device settings for the breaker that will coordinate with the high-side fuses. Therefore, the time overcurrent relays at the main collector feeder breaker can be coordinated with high-side fuses of the WTG step-up transformer. The 3.5 MVA WTG step-up transformers in the above example are protected by a 100 A current limiting fuse in series with a 71 A expulsion type fuse. The coordination between the phase TOC relay at the Main Feeder Breaker and the high-side fuses for a three-phase fault at the first WTG on the circuit appears in Figure 11.

The chief disadvantage of the non-directional phase time overcurrent setting is that its current pickup setting may be 8 – 12 times the full load capability of any individual WTG on the circuit, resulting in loss of sensitivity for low-current faults. For example, 51P relay curve (11F4-50/51P) in Figure 11 provides good collector feeder protection for the smallest conductor size on the feeder, but marginal protection for the WTG step-up transformer because the relay trip current setting is approximately ten times the full load current capacity of a single WTG. However, the high trip current setting of a 51P relay enables it to operate securely, regardless of the direction of current flow on the collector feeder. For this reason, non-directional phase time overcurrent protection schemes may be applied on collector feeders for which the system fault current is much larger than the combined output current of the WTGs on the circuit.

Non-directional instantaneous phase overcurrent (50P) elements can be set to provide instantaneous tripping for faults on the main collector feeder circuit. Ideally, the current pickup setting of the 50P element is set above the combined inrush current of the WTG step-up transformers on the circuit but low enough to see a 3-phase feeder fault at the farthest WTG on the circuit. Transformer inrush currents can be on the order of 8 – 12 times the full load current, based on the nameplate rating of the transformer. For example, the combined full load current of the 8 WTG transformers in the previous example is (8)(3.5 MVA) / (1.732)(34.5 kV) = 469 A. If the combined transformer inrush current is considered to be 10 times the full load current, then the combined transformer inrush current is 4690 A. If the fault current seen at the main feeder breaker for a 3-phase fault at the end of the collector feeder circuit is 10,520 A, then the 50P element may be set below 10,520 A but above 4690 A. If a 50P setting of approximately 80% of the 3-phase fault current at the end of the feeder is applied, then the 50P element could be set to trip at approximately 0.8(10,520) = 8416 A. If the CT ratio is 1200/5, then the 50P element could be set just below 8416/240 = 35.07 A, secondary. Therefore, a 50P setting of 35 A, secondary (= 8400 A, primary) could be applied. In cases where the transformer inrush current exceeds the instantaneous trip current setting required to detect a fault at the end of the collector feeder circuit, harmonic current blocking can be used to inhibit the phase instantaneous overcurrent element from tripping for transformer inrush [4]. Alternatively, since the highest transformer inrush current is usually within the first 3 - 5 cycles upon energization, the trip delay of the phase instantaneous overcurrent element can be increased from instantaneous to a delay of 10 - 12 cycles to bypass the initial transformer inrush current time duration.

It is important to note that a 50P setting based on a percentage of the fault current available at the end of the feeder may cause the main collector feeder breaker to trip as the current limiting fuse blows for a fault between any WTG transformer and its associated fuse. This can be remedied by setting a combination of instantaneous and definite-time overcurrent elements. The instantaneous 50P element can be set to provide instantaneous tripping for feeder faults between the main collector feeder breaker and the first WTG on the circuit. The additional definite-time phase overcurrent elements would be set at some percentage below the maximum fault current available at the last WTG on the circuit. Then, an appropriate time delay to provide coordination with the thermal damage curve of the conductor and to ride through the combined transformer inrush for the circuit would be applied.

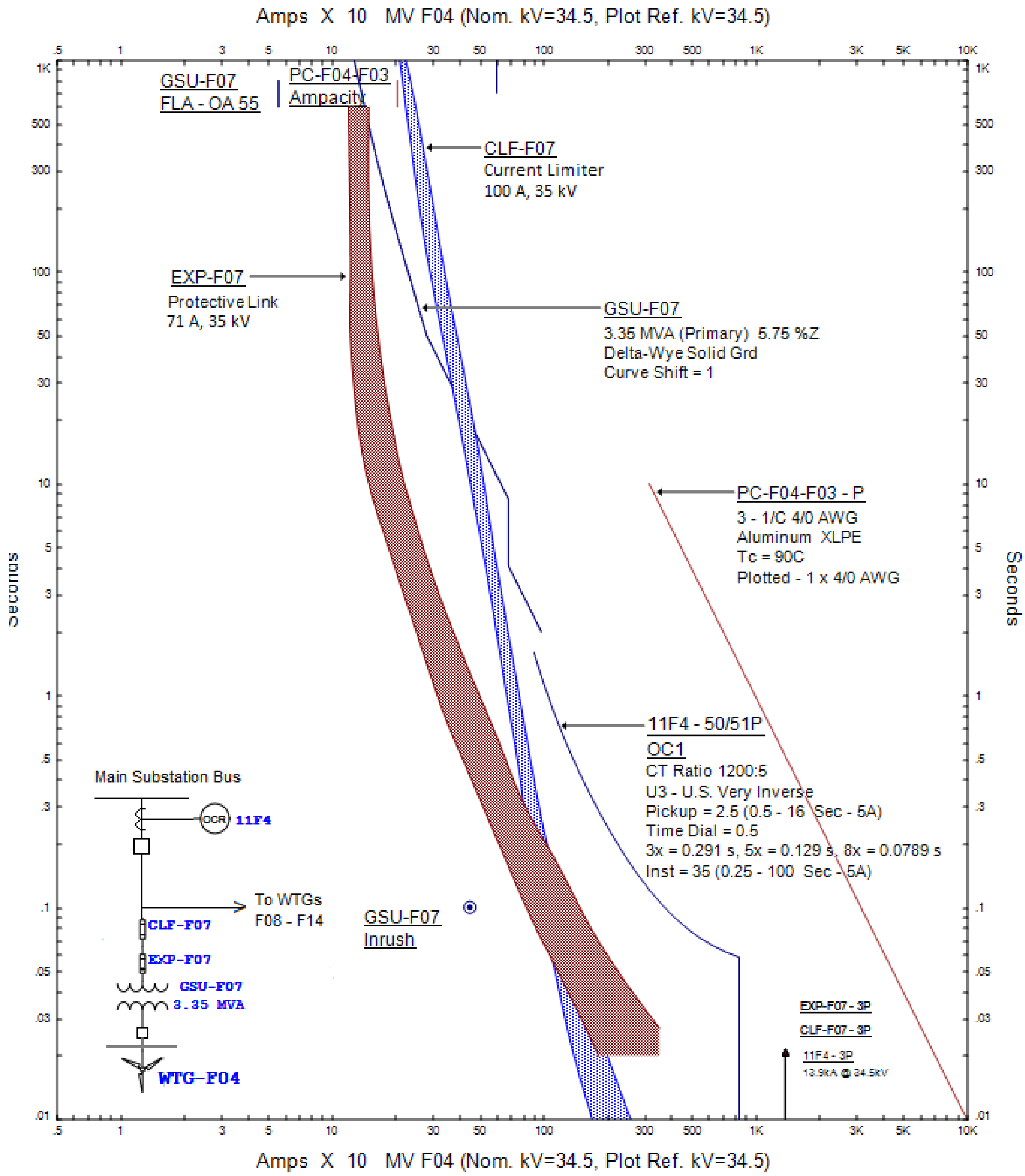


Figure 11: Non-Directional Phase Relay Time Overcurrent Coordination with WTG Fuses

The relatively poor sensitivity of the phase time overcurrent protection scheme can be mitigated for unbalanced faults by applying a non-directional negative sequence time overcurrent element (51Q). Because a 51Q relay operates on I_2 or $3I_2$, it can be set below balanced 3-phase load current. This enables the user to set the minimum operating current level of the 51Q relay more sensitively than that of the 51P, thus providing a better match with the minimum current at which the WTG transformer high voltage side fuse begins to melt. For coordination purposes, the 51Q element may be considered as an "equivalent" phase overcurrent element. Pickup, curve type, and time dial settings can then be derived for the "equivalent" phase overcurrent element and coordinated with downstream phase overcurrent devices. After the coordination is complete, the "equivalent" phase overcurrent pickup setting can then be multiplied by the appropriate factor to convert it to a negative sequence pickup setting for the 51Q in terms of $3I_2$ or I_2. [27]. With the lower trip current setting, a curve type can then be selected whose slope better matches the slope of the fuse characteristic curve, and a time dial can be selected to provide a closer margin of time between the 51Q and the high-side transformer fuse curve over a broader range of unbalanced fault current.

In the previous example the full load capacity of one of the eight WTGs is 57 A. Therefore, the equivalent minimum trip current setting of the 51Q can be set below the 455 A of all 8 WTGs but somewhere above the 57 A of a single WTG. Therefore, a setting of 130% of the full load capacity of one WTG can be established as the basis for the minimum equivalent phase current sensitivity (I_m) of the 51Q, where:

$$I_m = 1.3(57) = 74 \text{ A.}$$

However, the 71 Amp expulsion fuse will not blow at currents lower than about 140 A (approximately 2 times the continuous current rating of the fuse). Therefore, the minimum equivalent phase current pickup of the 51Q can be no lower than 140 A. Given the 1200/5 CT ratio, an equivalent phase pickup setting of 140 A primary would be 0.58 A, secondary. Therefore, the equivalent phase pickup setting for the 51Q can be 0.6 A, secondary (= 144 A, primary). If the 51Q operates on $3I_2$, then the $3I_2$ setting for the 51Q relay would be 1.732(144 A) = 249 A, primary [27]. Given the 1200/5 CT ratio, the $3I_2$ setting for the 51Q relay can be rounded up slightly to 1.1 A, secondary = 264 A, primary to account for the protective relay precision.

The coordination plot of Figure 11 with a 51Q time-current characteristic (11F4-50/51Q) set with the trip current pickup calculated above appears in Figure 12. The coordination between the 51Q and the fuse curves is based on the equivalent phase current pickup for the 51Q. After coordination is complete, the actual 3I2 pickup settings can be applied to the 11F4-50/51Q in the field. The time curve and time dial settings obtained from the equivalent phase current coordination can be applied directly to the 51Q element. The 11F4-51Q curve provides better coordination with the expulsion fuse curve for unbalanced faults that are too low for the 51P (11F4-50/51P) relay to detect. A large proportion of faults on a power system are unbalanced faults, and the 51Q element (11F4-50/51Q) provides good collector feeder protection as well as backup protection for the individual WTG step-up transformer during unbalanced faults. However, a 51Q relay will not operate for balanced 3-phase faults. Faults on underground collector feeder circuits that start as an unbalanced fault can quickly involve the un-faulted phases and become a 3-phase fault.

Non-directional instantaneous negative-sequence overcurrent (50Q) relays or elements can also be set at the user's discretion to provide instantaneous tripping for faults on the main collector feeder circuit. As with the 50P, the current pickup setting of a 50Q element may be set above the combined inrush current of the WTG step-up transformers on the circuit, but low enough to see a phase-phase feeder fault at the farthest WTG on the circuit. For example, if the fault current seen at the main feeder breaker for a phase-phase fault at the end of the collector feeder circuit is 8985 A, and the combined WTG transformer phase inrush current is 4690 A, then the equivalent phase pickup of the 50Q element may be set below 8985 A but above 4690 A. Given the 1200/5 CT ratio, a pickup setting of 25 A, secondary (= 6000 A, primary) could be selected for the equivalent phase pickup setting of the 50Q. The final setting based on 3I2 would therefore be 1.732(25 A) = 43.3 A, secondary (=10,393 A, primary). It is important to note that transient negative sequence currents may appear during breaker switching operations. Therefore, the 50Q element may need to be delayed 1.5 – 2 cycles to allow the transient currents to subside.

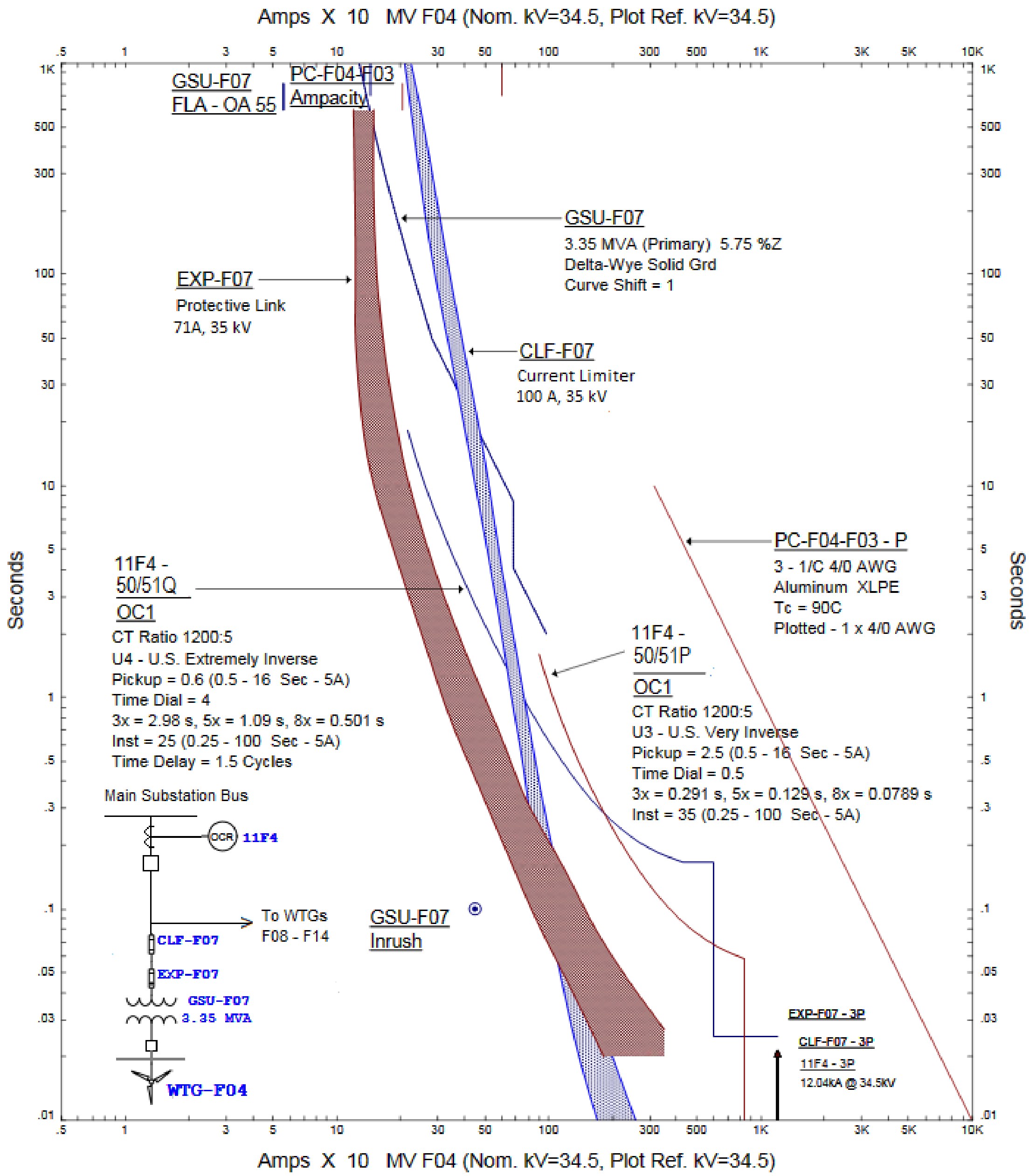


Figure 12: Non-Directional Phase and Negative Sequence Relay Coordination with WTG Fuses

Since the WTG output to the substation feeder breaker is essentially balanced, the current pickup of the neutral or residual ground time overcurrent (51N or 51G) element can be set relatively low, typically 10 – 30% of the phase time overcurrent setting. The curve type and time dial are then selected to coordinate with the expulsion fuse on the medium voltage side of the WTG step-up transformer. An example of the coordination between a 51G relay (11F4-50/51G) and the high-side fuses of a WTG transformer appears in Figure 13. In Figure 13 the trip current setting of the 51G relay is greater than the approximately 140 A current level at which the 71 A expulsion fuse begins to blow. A 0.6 A, secondary = 144 A, primary setting for the 51G places the 51G trip current setting at approximately 24% of the 51P trip current setting.

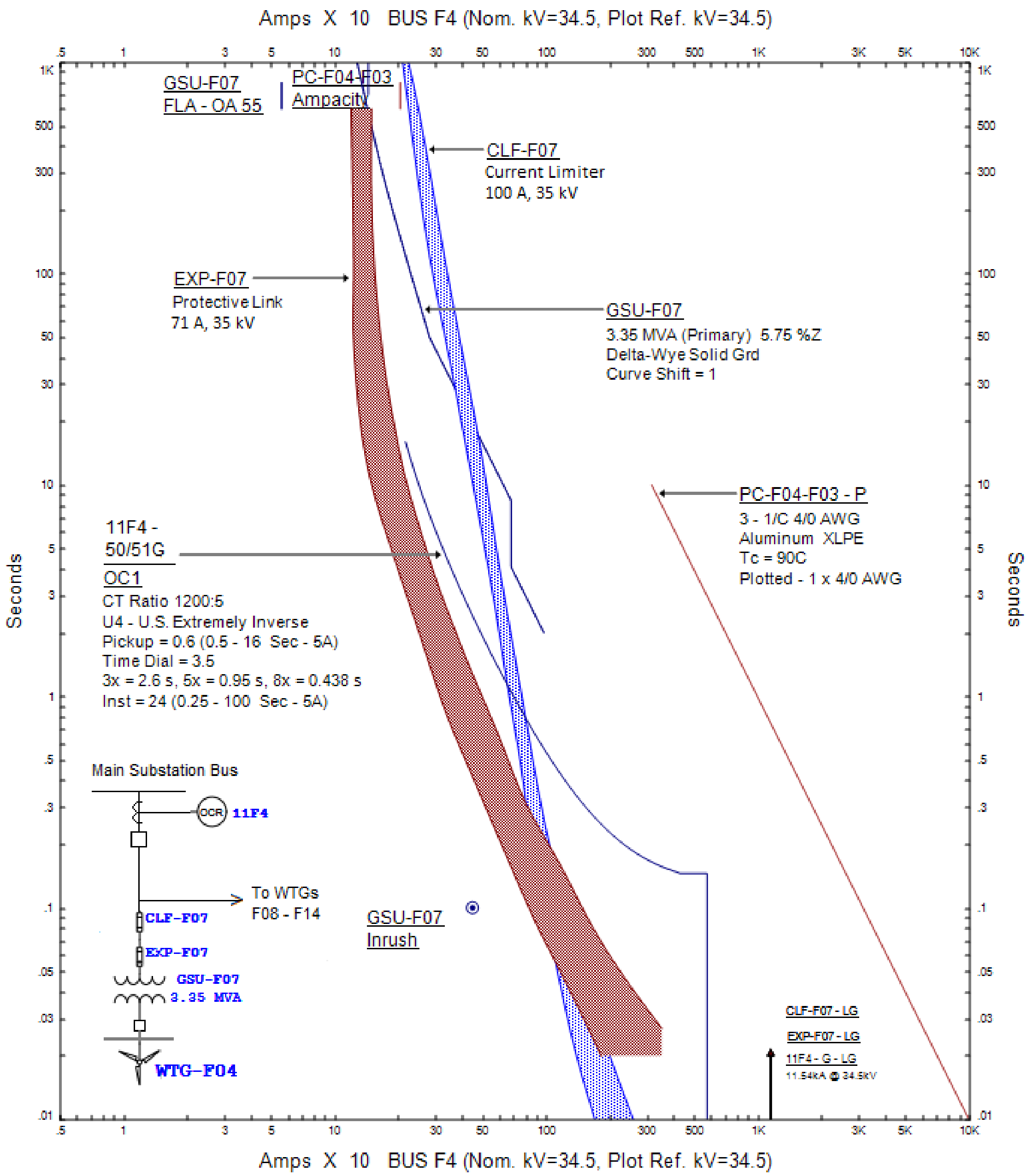


Figure 13: Non-Directional Ground Time Overcurrent Relay Coordination with WTG Fuses

Non-directional instantaneous or short time neutral or residual ground overcurrent (50N or 50G) elements can be set in much the same way as the phase elements. To provide instantaneous tripping for single phase to ground faults over the full length of the collector feeder, the 50G element may be set low enough to see a phase-to-ground feeder fault at the farthest WTG on the circuit, typically some percentage of the fault current value, but high enough to avoid potential mis-operation from any CT or system impedance unbalances during initial energization of the collector feeder circuit. If, for example, the fault current seen at the main feeder breaker for a single phase to ground fault at the end of the collector feeder circuit is 7200 A, then a 50G setting of approximately 80% of 7200 A would be 24 A, secondary = 5760 A, primary. This setting can be expected to be well above any zero-sequence current that would occur during collector feeder transformer inrush. Alternatively, a high-set instantaneous ground element can be set to detect a feeder fault up to the first WTG transformer on the feeder. A second ground overcurrent element can then be set to detect a phase-ground feeder fault at the farthest WTG on the circuit with a time delay to avoid thermal damage to the cable and to allow initial energization of the GSU transformers on the circuit.

3.1.1.2 Directional Overcurrent Protection

Directional phase time overcurrent (67P) elements can be set to provide increased sensitivity and speed. Directionally supervising the overcurrent element may provide the following features:

- Provide better coordination margins in systems where the fault current contribution from the WEP substation bus is similar order of magnitude to the full load current with all WTGs online
- Allow detection of faults on the low-voltage side of the WTG transformers
- Faster fault clearing times on the collector feeder, potentially reducing cable damage and cost
- Assist mitigation of arc-flash hazards

When the WTGs are online, the direction of power flow is from the WTGs to the substation main bus. The 67P relays operating at the substation feeder breaker can be set such that the forward direction is towards the WTGs on the collector circuit. The minimum trip setting of the 67P can therefore be set below the combined WTG output capacity of the collector feeder. Since the only current drawn by the WTGs in the forward direction will be station service current drawn by the WTGs while they are off line, the pickup current level for the directional phase time overcurrent element can be set above the aggregate station service load of the off-line WTGs and above the minimum melting current of the high voltage fuse at an individual WTG transformer. The curve type and time dial are then selected to coordinate with the fuse on the high voltage side of the WTG transformer, or with any low voltage trip devices such as breakers installed on the secondary side of the WTG transformer.

In the 8-WTG collector feeder example, the output capacity of a single WTG is 57 A, and the WTG step-up transformer is protected by a 71 A expulsion fuse. Since the minimum melt current of the fuse is approximately 140 A, the 67P trip setting may be set at or just above 140 A. Given the 1200/5 CT ratio, the minimum 67P trip setting would be 0.6 A secondary = 144 A primary. A plot of the resulting coordination appears in Figure 14, where the 67P relay is denoted as “11F4-67P”. In Figure 14 the 67P (11F4-67P) provides both collector feeder protection and backup phase overcurrent protection for the individual WTG step-up transformers for both three-phase and unbalanced faults.

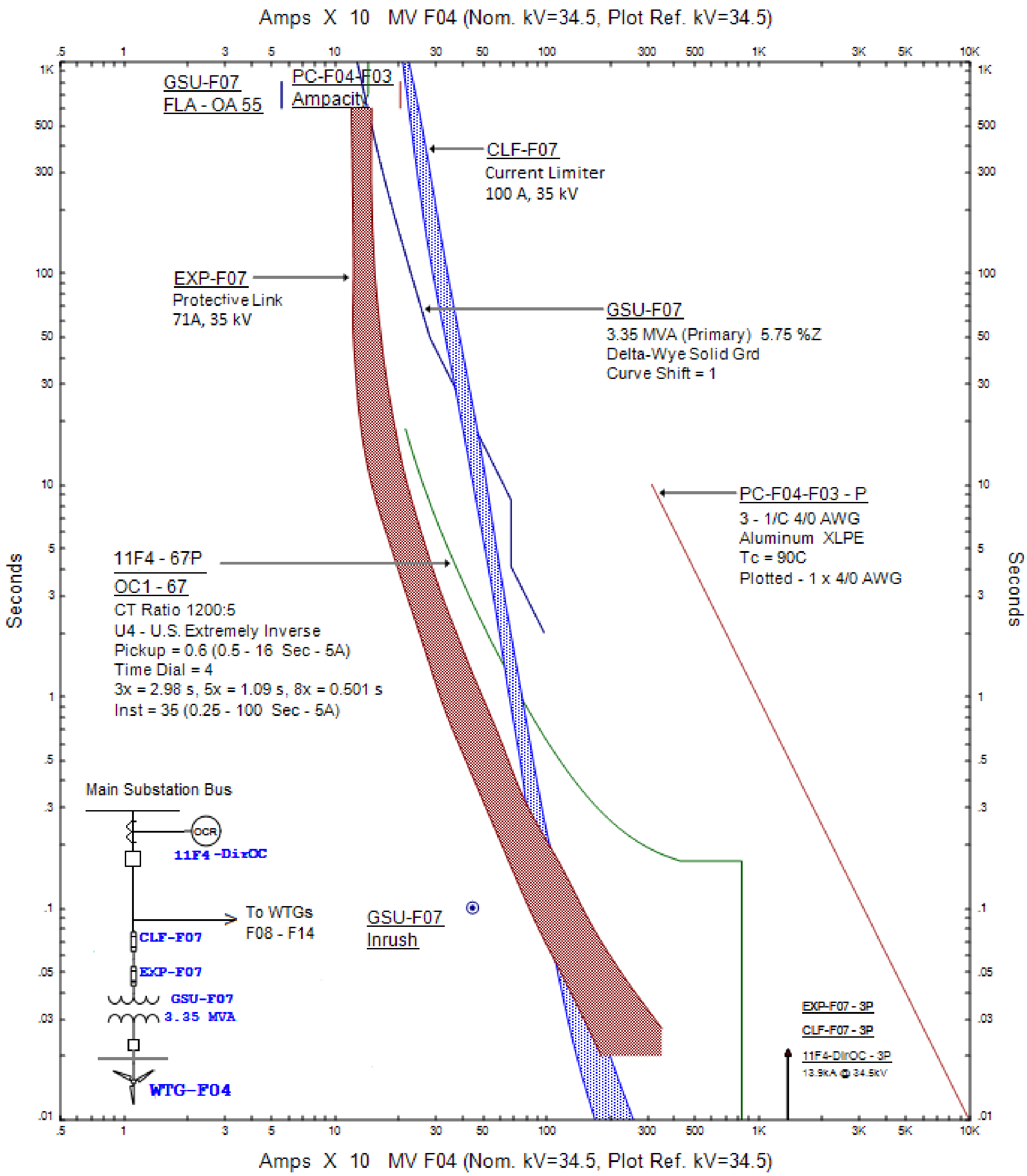


Figure 14: Directional Phase Time Overcurrent Relay Coordination with WTG Fuses

A 67P element usually determines the trip direction by comparing the line current with the system voltage. As such, it is important to manage the protection system's response to an inadvertent loss of voltage on one or more phases, such as the loss of a VT secondary fuse. Most electronic relays have loss of potential logic which either blocks the 67P element or allows it to operate non-directionally. Non-directional operation of the 67P during a high generation condition could result in a needless trip of the main collector feeder breaker. Blocking the 67P element for loss of voltage and relying on a backup 51P element with a higher trip current setting would be a secure solution.

Additionally, the directional characteristic angle and sensitivity settings are also selected to keep the 67P element from declaring a fault under certain operating conditions. Type 3 and 4 wind turbines can supply or absorb large amounts of reactive power at low real power outputs. This can result in an extremely wide range of power factor outputs of the feeders. In general, when the turbines are being operated in a voltage control mode, they will absorb reactive power when they are lightly loaded to counter-act the effects of the capacitance of the collector system. Conversely, the WTGs may be required to supply reactive power to the system to raise the voltage.

With the forward trip direction of the 67P element set towards the WTGs on the collector feeder, the characteristic angle of a conventional directional relay will be such that the current into the feeder lags the polarizing voltage approximately by the angle of the positive sequence line impedance. Such a characteristic may be superimposed on the capability diagram of the wind turbine generators as shown in Figure 15. In Figure 15, the operating area of a Type 4 WTG is shown with a maximum current magnitude of 1.0 per unit. With zero real power production, the power electronics could still export or import up to 1.0 per unit of reactive power covering all of the second and third quadrants. In the case of zero real power production, the collector bus might export a small amount of real power into the feeder to supply auxiliary power to the WTG and possible losses in the feeder cable itself.

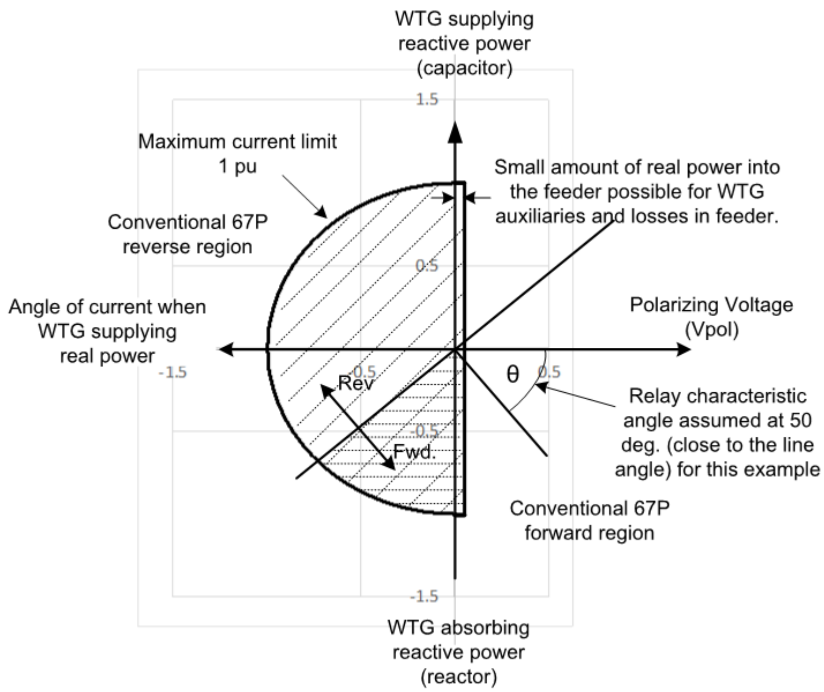


Figure 15: Conventional Phase Directional Element 67P Voltage and Current Phasor Diagram and Operating Region of Wind Generation

It can be seen from Figure 15 that there is an area in the third quadrant and a small area in the fourth quadrant where a possible overlap of the normal operating conditions and the region being declared as forward by a conventional 67P relay. In this case, one could modify the relay characteristic angle to be less than the line so that it will have a more limited operating region in quadrant 3. The minimum operating current could be set higher than the maximum real power supplied to the feeder (for auxiliary power with no wind, or to cover losses in the feeder) under any condition. However, the conventional 67P relay with fixed operating region is generally not optimum to provide sensitive feeder protection.

Some 67P relays have independently adjustable directional characteristics that can modify the region for forward faults to be clear of the operating region of the wind turbine generator. An example of this characteristic is shown in Figure 16. In Figure 16, angles α and β are independently adjustable. This characteristic prevents any operation in quadrant 3. The minimum operating current can be set to prevent operation in small areas of quadrants 1 and 2 due to small amounts of real power that might be supplied to the wind turbine generators during no wind periods.

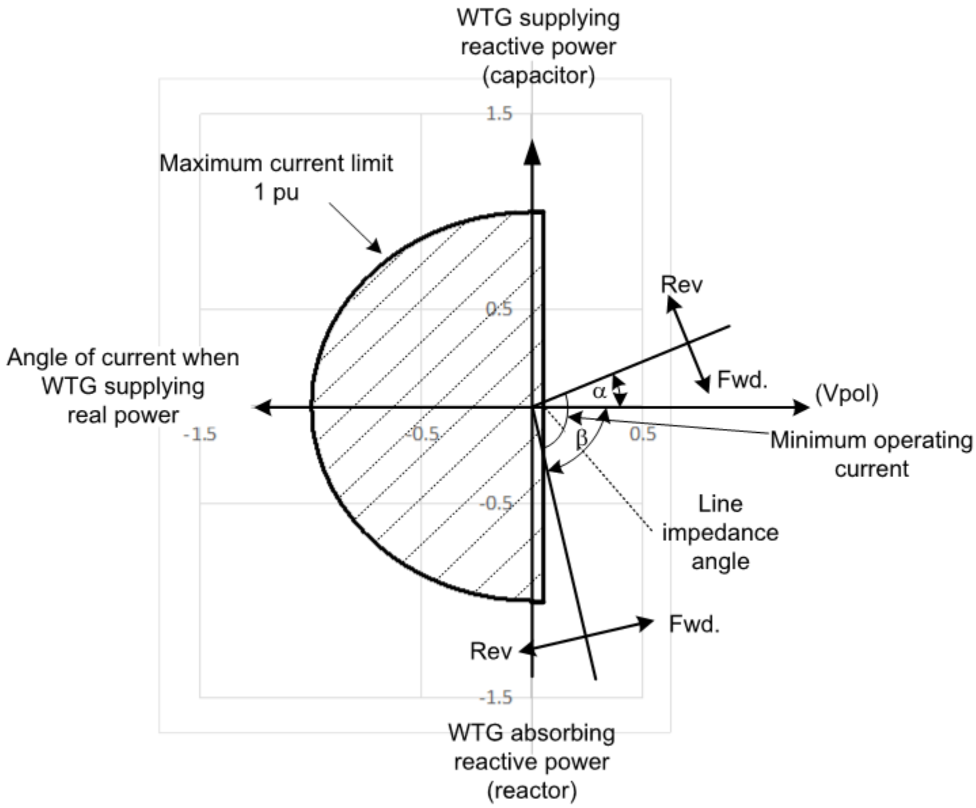


Figure 16: Phase Directional Element 67P With Adjustable Directional Blinders

Another type of 67P relay may have a load blinding feature that could be shaped to restrain for any power flow into the collector bus from the feeder, including low real power and high reactive power. One type of relay uses a positive sequence impedance element to define the load area and block the overcurrent function if the impedance is in the load area. Figure 17 shows an example of a load blinding function that could be applied. The overcurrent function will be enabled only when the measured impedance is in the first quadrant. Note that a minimum operating current setting will prevent the relay from operating on the very high impedance which will be measured on the right side of the RX diagram when there is no wind and a small amount of real power is supplied to the WTG for auxiliaries and line losses.

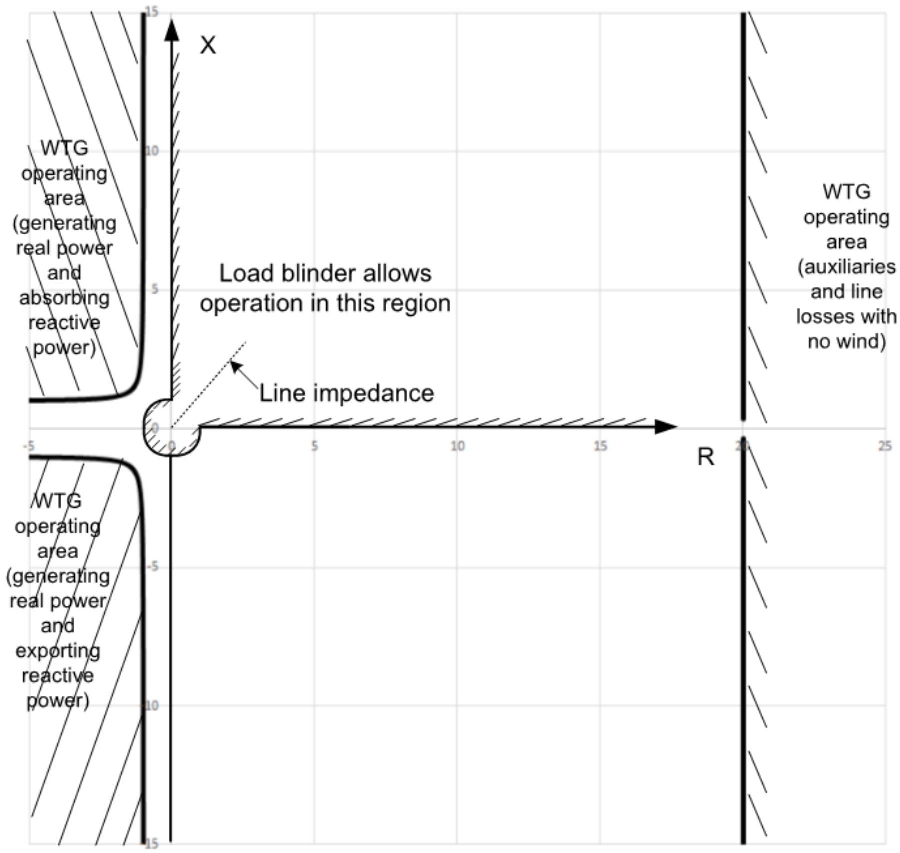


Figure 17: RX diagram showing normal operating regions of WTG and example positive sequence impedance measuring load blinding characteristic

Additional discussion of directional phase overcurrent setting considerations for wind turbine generator operation and simulation results of directional element operation for various modes of generator operation can be found in Appendix A.

In some electronic multi-function relays, negative sequence polarization techniques are used to control the operation of the 67P element. The negative sequence element settings used for directional control in typical protection applications may not provide reliable operation for directional protection of collector feeder circuits when Type 4 turbines installed. This is because Type 4 turbines may produce very little negative sequence current during faults. Type 3 turbines may also provide little negative sequence current during faults when their response is being controlled by their electronic controls. Chen, Shrestha, Ituzaro, and Fischer [21] described an event in which a collector feeder breaker tripped correctly on a 67P for a BCG line fault, but the 67P elements for both un-faulted collector feeders tripped incorrectly because the WTGs on the un-faulted feeders were not able to produce enough negative sequence current to enable the feeder relay to correctly determine the direction of the fault. The authors' solution was to change the line impedance angle setting in all the relays to about 10°. Lowering the line impedance angle to 10° would move the boundary angles of the positive sequence forward directional trip zone to 100° and 280°, respectively on an impedance diagram, or 80° and 260°, respectively on a voltage/current diagram, such as that shown in Figure 15.

It is important to understand that the solution noted in [21] may not be generally applicable in all cases. That solution was determined for a control system with a particular type of WTG. In general, because of the uncertain characteristics of the negative sequence current contribution from WTGs negative sequence directional protection is difficult to apply. If it is possible to determine the maximum level of negative sequence current that could be contributed to an external fault (outside the protected feeder) from the WTG, then setting the pickup of the negative sequence directional overcurrent function higher than its minimum pickup setting would keep it secure in the event of such an external fault. In many cases, the magnitude of negative sequence current is intentionally minimized by the WTG controls. In such cases, the negative sequence current from the collector bus to an internal fault would be significantly larger than the contribution to an external fault. Therefore, a simple non-directional negative sequence overcurrent function could be secure and dependable. Note that it is still important for security that non-directional negative sequence time and instantaneous overcurrent protection coordinate with the high-side fuse of the WTG step-up transformer in a similar fashion to the 50/51G elements as shown in Figure 13.

The directional phase instantaneous overcurrent relay or element can be given the same pickup setting as the 50P because it will detect the same collective inrush of the WTG transformers upon energization as the 50P. Some electronic multifunction relays have harmonic current blocking functions. In cases where the transformer inrush current exceeds the instantaneous trip current setting required to detect a fault at the end of the collector feeder circuit, harmonic current blocking can be used to inhibit the directional phase instantaneous overcurrent element from tripping for transformer inrush [4]. Similarly, the considerations discussed above for directional phase instantaneous overcurrent elements apply to directional neutral or ground instantaneous overcurrent element settings.

Directional neutral or residual ground time overcurrent relays (67N or 67G) can also be applied for collector feeder protection. However, because they are normally set to coordinate with the high-side fuse of the WTG step-up transformer, the minimum trip current setting of a 67N or 67G will be the same as that of a 51N or 51G, and the coordination would be the same as that shown in Figure 13. Similarly, the setting criteria and coordination considerations for directional neutral or residual ground instantaneous overcurrent elements are essentially the same as those for non-directional 50G or 50N elements.

3.1.2 Voltage and Frequency Protection and Coordination

3.1.2.1 Continuous Voltage and Frequency Range

Wind electric plants may operate within a limited voltage range at the point of interconnection due to the intermittent nature of these generators, and the variation in real and reactive power flow across the entire range of plant output. In addition, Transmission Providers are normally required by regulating authorities to operate their systems at a normal voltage range of +/-5 percent from the nominal system voltage. The collector circuits and substation may not require specific under/overvoltage relaying since the wind WTG relaying and control functions are designed to keep voltages within acceptable limits. The wind turbines might include voltage relaying for generator protection as well as voltage control equipment settings to enable them to recover from some types of system voltage excursions, per regulatory standards such as North American Electric Reliability Corporation Standard PRC-024 [23]. Any under/overvoltage protection schemes installed on the collector circuits or in the collector substation would also have over/undervoltage settings that would provide protection while not interfering with the generator's ability to recover from temporary system voltage excursions.

Frequency response requirements for WTGs in North America are not presently addressed by regulating authorities. However, it is important to note that some standards define certain frequency protective relay settings to maximize the generating unit's ability to remain connected during a frequency excursion.

3.1.2.2 Temporary Overvoltages

Wind plants can experience higher transient overvoltages (TOV) than typical distribution systems. Collector circuit ground faults are a primary cause of TOV. For ground faults, the collector circuit has its primary source of zero sequence current supplied from the main transformer. Ground faults on the collector circuit will be cleared by the collector relaying. When the breaker is tripped following the fault, this opens a window of risk for TOV. The severity depends on the degree of system grounding on the remaining circuit. Where effective grounding is not provided, the voltages on the un-faulted phases will be higher, up to 1.73 times nominal phase to ground voltage. This is an important consideration in the selection of surge arresters. When collector circuits have underground cables, the cable capacitance further increases the un-faulted phase voltages. A common way to reduce TOV is to use grounding transformers.

A main grounding transformer may be needed on the low side of the main transformer, if the winding connections do not provide a system ground allowing for a zero-sequence source of fault current. A properly rated grounding transformer will reduce the overvoltage seen by the un-faulted phases during line to ground faults. Grounding transformers are also typically installed on the collector circuits at the substation to provide a ground reference when the collector circuit breaker is opened following a fault. The protection of these units is normally by the collector relaying. Absent these grounding transformers, the TOV can exceed the 173% value due to the circuit capacitance. Therefore, the application of grounding transformers can be an effective means to limit TOV during the time period between the fault and the shutdown of the wind turbines on the faulted collector circuit.

Other ways to reduce TOV include the application of high-speed grounding switches on the collector circuits and the use of transfer trip schemes. Note that similar overvoltage conditions may occur when the collector circuit breaker opens inadvertently in the absence of a fault. This may occur due to self-excitation, saturation, or ferro-resonance conditions. In many cases TOV cannot be avoided completely, and this problem is normally addressed by proper insulation coordination.

3.1.2.3 Voltage and Frequency Ride-through

The wind turbine protection scheme may include voltage and frequency relaying to protect the generator. For example, some wind turbines may trip for frequencies at or below 95 percent of nominal, or above 103 percent of nominal, with an appropriate time delay. The WTG protection scheme may also trip the unit at voltages below 90% of nominal or above 110% of nominal, with an appropriate time delay. Specific voltage and frequency trip settings may be obtained from the WTG vendor. The vendor's voltage and frequency protection settings are typically outside of the minimum limit settings defining the "no trip zones" for voltage and frequency as specified by area regulatory authority standards to enable the WTG to remain connected to the power system during a voltage or frequency excursion.

For example, in North America, NERC Standard PRC-024 does not specifically require under/overvoltage and under/overfrequency relay protection for WTGs, collector feeders, or the POI. However, if multifunction electronic relays are installed for protection, either at the collector feeders or the POI, the NERC standard requires voltage and frequency elements to be set to allow the generation to remain on-line for voltage and frequency disturbances. . If the specific voltage and frequency protection settings for the WTGs are known, then the voltage and frequency settings in the collector feeder relay can be made to allow sufficient time for the WTG voltage and frequency protection to operate first. In the absence of specific WTG settings, the voltage and frequency settings in the collector feeder relay may be set per PRC-024 with enough margin to enable them to be outside of the "no trip zone" described by the standard.

3.1.3 Arc Flash Protection

The arc flash levels on the low side of the wind turbine generator (WTG) step-up transformers can be very high. To reduce the arc flash hazard in this area the substation feeder relays may be set to trip high speed for faults on the low voltage side of the WTG GSU transformer, forgoing coordination with the GSU protection. In addition to the normal directional overcurrent elements described in Section 3.1.1.2, an additional set of directional overcurrent elements can be enabled specifically for arc flash protection during maintenance periods (typically called a "maintenance mode"). The fast and sensitive "arc flash" elements discussed in this section are normally enabled only in maintenance mode and are disabled for normal WTG operation so that the normal directional overcurrent elements can maintain proper overcurrent coordination.

Typically, there are two elements used. The first element is a directional phase overcurrent element (67P) which is used to detect three phase faults. The second element is a directional negative sequence overcurrent element (67Q), which will be used to detect single-line-to-ground, line-to-line, and double-line-to-ground faults. Generally, the high side of the WTG GSU transformer is delta connected. This configuration is an open circuit in the zero-sequence network, so it is not possible to use ground overcurrent elements to detect faults on the low side of the WTG GSU transformer.

The directional phase overcurrent element can usually be set to pick up for the minimum expected three phase arcing fault current that the feeder relay will see for a fault on the low side of any WTG GSU transformer. It is important to account for the arcing impedance when setting this element, as the ultimate goal is to protect against an arcing fault, and the arc flash study will be using the arcing current in its calculations. Similarly, the directional negative sequence overcurrent element can usually be set to pick up for the minimum expected negative sequence arcing fault current for a single-line-to-ground, line-to-line, or double-line-to-ground fault current that the feeder relay will see for a fault on the low side of any WTG GSU transformer. The directional negative sequence overcurrent element can typically be set quite sensitive.

The arc flash/maintenance mode elements are often set to trip instantaneously. However, they may require enabling supervision via SCADA or via the breaker status and a short delay to avoid unwanted operation on inrush during energization of the feeder circuit. They may also be set with a delay to allow the feeder to energize in the maintenance mode. The sensitive phase directional element is also checked to verify that it will not operate on generation current when the WTGs are absorbing reactive power from the system, as discussed in Section 3.1.1.2.

3.1.4 Removal of WTGs from Collector Feeders Under Fault

The generator protection system for the WTGs is provided by the WTG vendor as part of the overall generator control system. WTG protection and control systems are equipped with over/undervoltage protection, over/underfrequency protection, overcurrent protection, generator winding and bearing temperature, metering, disturbance recording, power flow control, and communications. A fault on the collector feeder will cause the main feeder breaker at the substation to trip. When the WTG protection and control system detect the resulting loss of voltage and load, it typically trips the WTG breaker to take the unit off-line and changes the angle of the blades to allow them to stop. The WTGs cannot be brought back on-line until the collector feeder has been successfully reenergized by the main feeder breaker at the substation.

3.2 Grounding Transformer Protection

The protection of each component of an electrical power system as well as the overall system is an essential aspect of plant design. The grounding transformer is an important element of the system that provides a system ground reference and aids in the control of Temporary Overvoltage conditions.

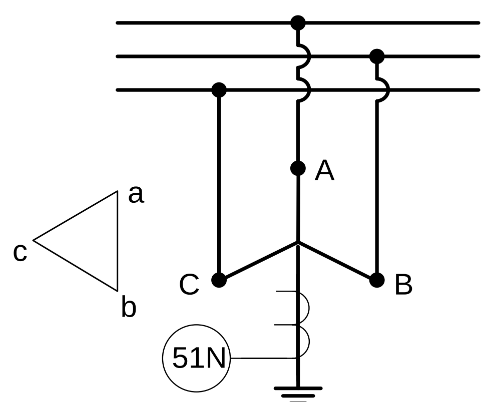


Figure 18: Delta-Wye Grounding Transformer

There are basically two types of transformer configurations [connections] that might be selected for the application of a Grounding transformer. The first is a two-winding transformer whose primary winding connected to the system that requires the ground, is connected in grounded-wye and whose secondary winding is connected delta [Figure 18]. The second two-winding transformer is the zigzag transformer [Figure 19] which is usually more cost effective to apply than the typical delta-wye transformer mentioned previously.

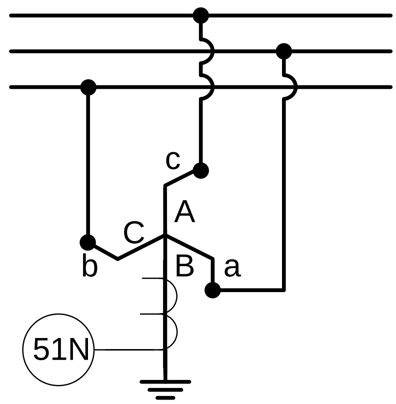


Figure 19: Zig-Zag Grounding Transformer

The grounding transformer supplies zero sequence fault current to allow detection of the fault and tripping by the appropriate relays. Though either of the transformer configurations may be protected by overcurrent relay elements (51) or differential relay elements (87), the application of overcurrent relay elements is typical. The protective relaying and current transformers on the grounding transformer itself can filter out zero sequence current for internal transformer faults by use of delta connected CTs or by the internal compensation in the relay. The application of overcurrent relay elements would generally include a 51 element on each phase and a 51N element connected in the neutral-ground path. Internal faults are typically detected by overcurrent relays which can respond to the positive and negative sequence fault currents, allowing the transformer relaying to restrain for ground faults external to the transformer. A separate neutral CT and ground overcurrent relay can be used to provide backup ground fault protection, selectively coordinated with bus and/or collector circuit ground protection. Differential relay elements, by design, only respond to faults internal to the ground bank.

3.3 Bus Protection

The low-voltage bus in a collector substation of a wind electric plant can be a wide variety of voltage levels with 34.5 kV being the most common. This is a voltage that is also commonly used for distribution systems. Although the bus voltage is similar, there are two significant differences between a collector substation and a distribution substation. First, there are multiple sources of power connecting to the circuits out of the collector substations. Second, in many cases the power transformers are significantly larger. It is common to have transformers larger than 100 MVA in collector substations. The larger transformers push the bus fault duties higher, which drives the need to clear the bus faults faster than the time delayed overcurrent relaying would permit. Due to these differences, it is common to apply bus protection in collector substations that are similar to the protective relay systems applied to transmission voltage buses.

The IEEE Guide for Protective Relay Applications to Power System Buses, C37.234 [29], is a very complete guide for the protection of substation buses. It is not the intention of this report to include the full content of that Guide. The following is a brief description of three different types of bus protection that would be suitable for a collector substation.

3.3.1 Zone-Interlocked Scheme

The zone-interlocked scheme is by far the least expensive of the bus differential schemes. It is most often applied on distribution substation buses where there is only one source of fault current and multiple feeders servicing load. Although this is not the case for the collector substation in most cases, the power transmission network fed through the substation step-up transformer is the most significant source of current to a bus fault. Figure 20 shows the typical collector substation simplified one-line diagram with a zone-interlocked scheme applied for the bus protection. The substation step-up transformer is connected to the bus through the M or Main breaker.

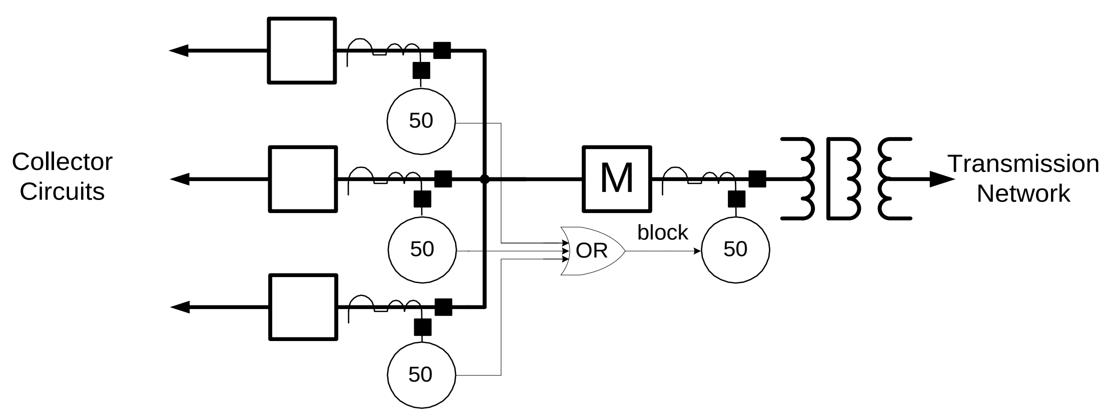


Figure 20: Zone Interlocked Bus Differential

Non-directional instantaneous overcurrent elements monitor the current through the line breakers and send a blocking signal to the bus protection relay for a line fault. The bus protection relay is another instantaneous overcurrent element that monitors the current from the step-up transformer. The collector line and the bus protection relay elements may be elements in multifunction relays which are used for other functions. The overcurrent functions for the line could be part of the line relay, and the overcurrent function for the step-up transformer could be part of the transformer relay. The bus protection overcurrent function pickup will need to be set above the maximum current output of the plant, with a margin, so that the relay will not pick up under load or for the fault current contributed from the WTGs.

The bus protection overcurrent element is unable on its own to distinguish between a bus fault and a collector line fault. For a collector line fault, the line overcurrent relay will operate and send a blocking signal to the bus overcurrent relay. For a bus fault, no blocking signals will be received so that the bus relay will trip after only a short coordination delay. The pickup level of the line overcurrent relays is typically more sensitive than the main breaker overcurrent relay, and the accuracy performance class of the current transformers (CTs) used by the line relays is usually equal to the accuracy performance class of the CTs used by the bus relay to enhance the security of the scheme for line faults. However, it is important to set the line phase overcurrent relays above the maximum fault current contribution from the WTGs for a bus fault. Considering there may be little or no negative or zero sequence fault current contribution from the WTGs to a fault, more sensitive negative and/or zero sequence non-directional overcurrent functions may also be used to provide the blocking signal to the bus protection.

The presence or absence of zero sequence current contribution from the WTGs is easily determined by knowing whether any grounding transformers or neutral grounding connections are applied on the lines. The presence or absence of negative sequence current is not obvious and will need to be determined from the WTG supplier, or whoever is responsible for setting the control systems on the WTG interface. If there are no sources of negative and zero sequence current on the WTGs or lines, the limitation on sensitivity of the line unbalance overcurrent functions will be the capacitive current coming from the line shunt capacitance during unbalanced faults.

The bus blocking signal circuit may be implemented using relay contact outputs from the line relays and an input on the bus relay. The line relay contacts are wired in parallel to operate the input on the bus relay for line faults. This type of scheme can also be implemented over point to point communication circuits or over a local area network. The advantage of this type of bus protection is that functions in relays that will be required for line and transformer protection can be used so that no additional relays and CTs will be needed. The disadvantages are that the bus protection will not be as fast as other schemes, sensitivity to high impedance bus faults is limited, complex networking between devices is required, and coordination for both sensitivity and speed is required between the multiple elements of the scheme. Note that sensitivity limitations for unbalanced faults can be mitigated significantly by the possible application of sensitive negative and/or zero sequence overcurrent detectors in the lines.

3.3.2 Percentage-Restrained Differential

The basic differential principle is to sum each phase of all the current flowing into and out of the bus and feed the resultant of the combination into an overcurrent relay element. The restrained or percentage differential protection is an enhanced variation of the basic differential principle. To insure security against mis-operation for line faults, even when the CTs are not performing perfectly due to high fault currents, the current being supplied by each of the circuits connected to the bus is monitored. The currents in the branches are individually measured and used to develop a restraint current that is indicative of the current flowing through the zone of protection. Typical methods are to sum the magnitudes of the branch currents or take the maximum of the branch currents.. The operate current is the vector sum of all the currents flowing into and out of the bus. The restraint value is compared with the operate current to determine if there is a line or bus fault. The higher the fault current, the greater the restraint value, so more differential current is required to operate the relay. At high current levels, the error current produced by poor performing CTs is greater, but this type of differential relay requires more operating current in this situation so that the operate current caused by the CT performance error will not result in an operation of the relay for an external fault. For bus faults with fault impedance, the fault currents are low, restraint is low, so the sensitivity for these low current magnitude internal faults are very good. Figure 21 shows the basic current circuit design for this type of relay scheme.

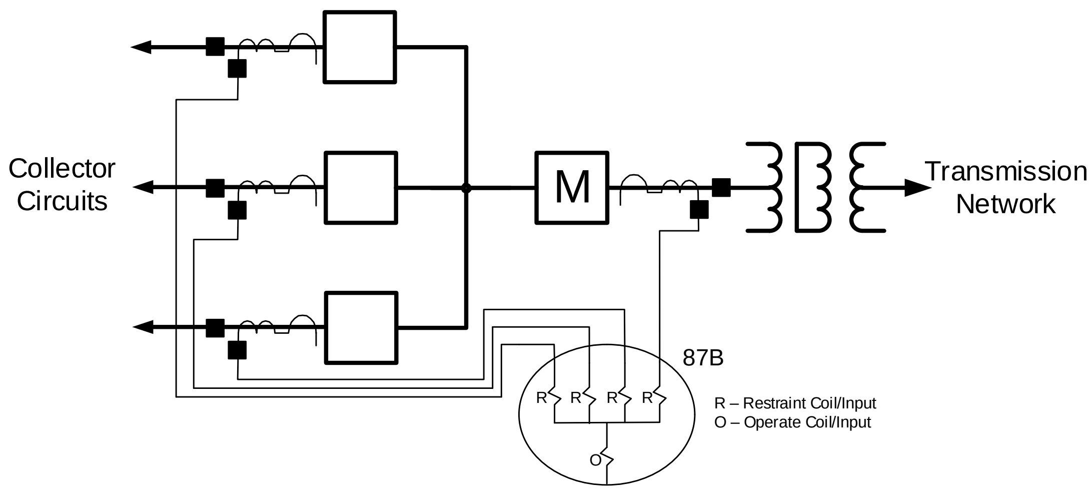


Figure 21: Percentage-Restrained Bus Differential

The impedance in the secondary current circuits for each of the power elements connected to the bus needs to be kept to a minimum, which is normally not a problem for the compact collector substation. The maximum magnitude of a bus fault needs to be taken into consideration when specifying the CT accuracy. Since the internal impedance of modern relays is low, the CTs need not be dedicated to just the bus differential relay. A line relay or a transformer relay can share common CTs with the bus relay. For some relays, the CTs do not have to be on the same ratio in that the ratios of all the in-feeds are normalized by the relay settings.

The advantage of this type of bus protection is that the relays are sensitive, fast and secure. The CTs for the different circuits do not need to have matching accuracy classes, and multi-ratio CTs do not need to be on their full-turns ratio. The CTs used by the bus differential relays can also be used for other functions if the impedance of the secondary circuit is kept low. The disadvantages are that the secondary currents from the set of CTs associated with each of the circuits connected to the bus are connected directly to the relay, and that may require the impedance of these circuits to be kept to a minimum to provide acceptable CT performance during a fault.

3.3.3 High Impedance Bus Differential

On the surface, the high impedance bus differential appears to be configured like that of the most basic of bus differentials. The outputs of all the CTs for the circuits connected to the bus are summed per phase and fed into an operating circuit of the relay. That is the only characteristic a high impedance bus differential has in common with other types of bus differential relay schemes. The high impedance bus differential system avoids the problem of poor performance of CTs for high current through fault conditions by making the impedance of the operating circuit very high. This configuration forces the error differential current through the CTs rather than through the relay operate circuit. For an internal bus fault, the CTs of all contributing circuits to the bus will be driven into saturation. The voltage produced by the CTs in saturation is impressed across the operate circuit of the bus differential relay causing it to operate. The voltage produced by the CTs is based on the accuracy class of the CTs. The relay is set to operate based on a voltage level, not a current level. To obtain the greatest sensitivity to high impedance bus faults, the impedance between the CTs and the common point of all the CTs is normally kept low and matched. The voltage setting level is based on the voltage drop across the highest impedance circuit between the CTs and the common point. For this reason, the common point for most applications is not at the relay but at a cabinet located in the substation yard at equal distance from all the CT sets. A four-wire cable is then connected between the junction box and the relay carrying the resultant differential signal.

The CTs used for a bus differential circuit can only be used for this application due the high impedance and high voltage of the circuit. For the best performance of the differential circuit, all the CTs applied to this circuit normally have the same accuracy class and are connected on the same ratio. To avoid potential damage to multi-ratio CTs, it is important for the CTs to be tapped at full ratio. If the CTs are tapped at a lower ratio, a higher voltage than what is applied to the operation circuit of the relay can be produced on the unused windings. This voltage could be higher than the rating of the insulation of the CT. For best performance of the bus differential system, auxiliary CTs are not normally used to match the CT ratios. However, there are ways to apply high accuracy auxiliary CTs in the circuit and still have a secure and functional system. Figure 22 shows the application of a high impedance bus differential relay.

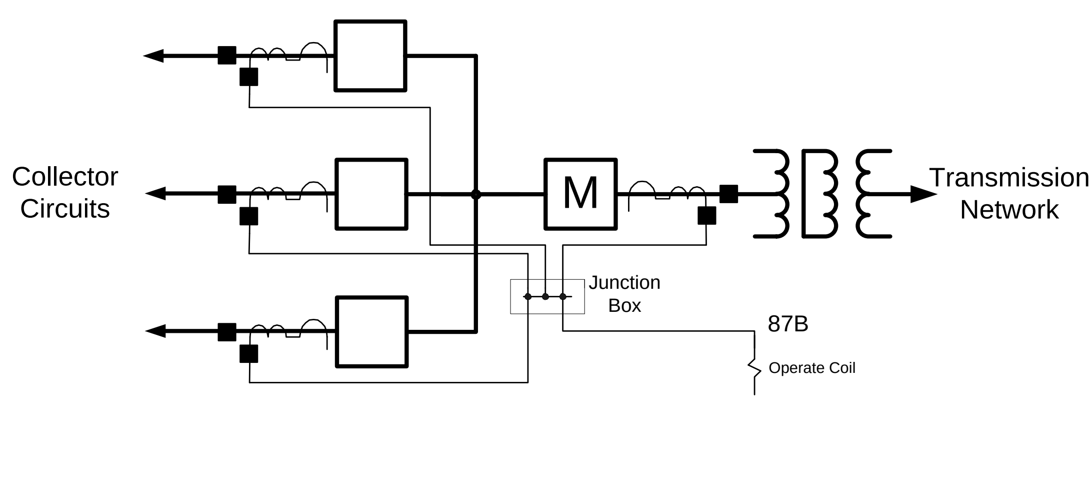


Figure 22: High Impedance Bus Differential

Advantages of high impedance bus protection include:

- The relays are sensitive, fast, simple, and secure.
- The CT secondary circuits are not wired all the way to the relay.
- The CT wiring at the relay is very simple, with only four terminations.

The following are disadvantages of high impedance bus differential protection:

- A junction box in the substation yard is needed to terminate the CTs. The only way to circumvent this requirement and still have the maximum sensitivity for the scheme is to locate the relay at equal distance to the CTs.
- The CTs for this scheme are dedicated to the scheme.
- All CTs are connected for the same ratio, preferably using the full turns ratio of the CTs.
- If some CTs in the scheme have a different accuracy class rating, the differential setting may be dependent on the CTs having the lower accuracy class rating.

3.4 Main Transformer Protection

The Main Power Transformer is likely the most expensive piece of equipment in the collector substation. The high cost of repair or replacement and the possibility of violent failure or fire involving adjacent equipment makes limiting the damage a major objective. It is important to carefully consider the protection characteristics of relays that will be applied for transformer protection, particularly for transformers of larger sizes. It is common to have transformers greater than or equal to 100 MVA in collector substations.

There are multiple ways to protect main power transformers that offer varying degrees of sensitivity, speed, and selectivity. The selected protection scheme may balance the best combination of these factors plus overall economics, while minimizing:

- Cost of repairing damage
- Cost of lost production
- Adverse effects on the balance of the system
- Spread of damage to the adjacent equipment
- Duration of the unavailability of the damaged equipment

Figure 2 shows common types of collector substation transformer configurations.

The IEEE Guide for Protecting Power Transformers, C37.91-2008 [30] provides a complete guide for the protection of substation power transformers. It is not the intention of this report to include the full content of that Guide. The following is a brief description of the different types of transformer protection that would be suitable for a collector substation.

3.4.1 Transformer Differential Protection

Current differential schemes are commonly used for protecting power transformers. Current differential protection has the following advantages:

- Provides faster protection and can limit equipment damage
- The location of the fault can be determined more precisely
- Accurate fault location allows for auto restoration techniques
- High speed clearing can significantly lower the arc flash incident energy

Figure 23 below illustrates the basic concept of the current differential scheme.

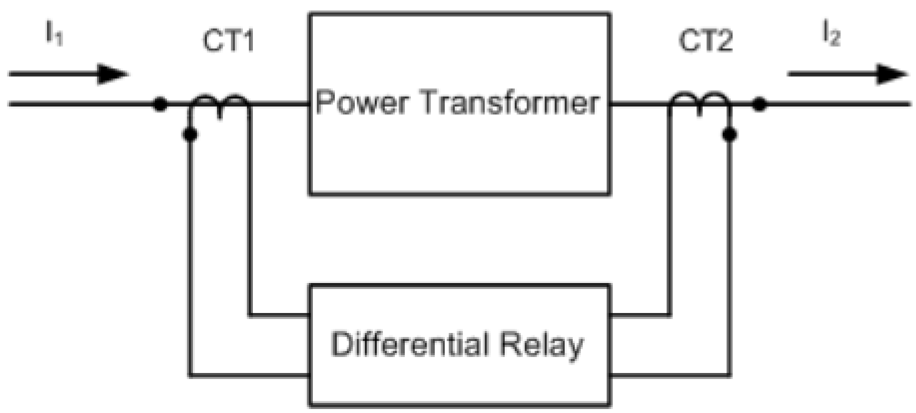


Figure 23: Basic concept of the current differential protection scheme [30]

If the ratios of CT1 and CT2 are 1:1, the operating current, I_0, which is the difference between the current entering one winding and the current leaving the other winding, can be obtained by the following equation:

$$I_0 = I_1 - I_2$$

where

I_0 is the operating current

I_1 is the current entering the transformer

I_2 is the current leaving the transformer

Figure 24 shows the transformer differential protection scheme connections for a wye grounded-wye grounded transformer with a delta-connected tertiary winding that is also brought out to bushings.

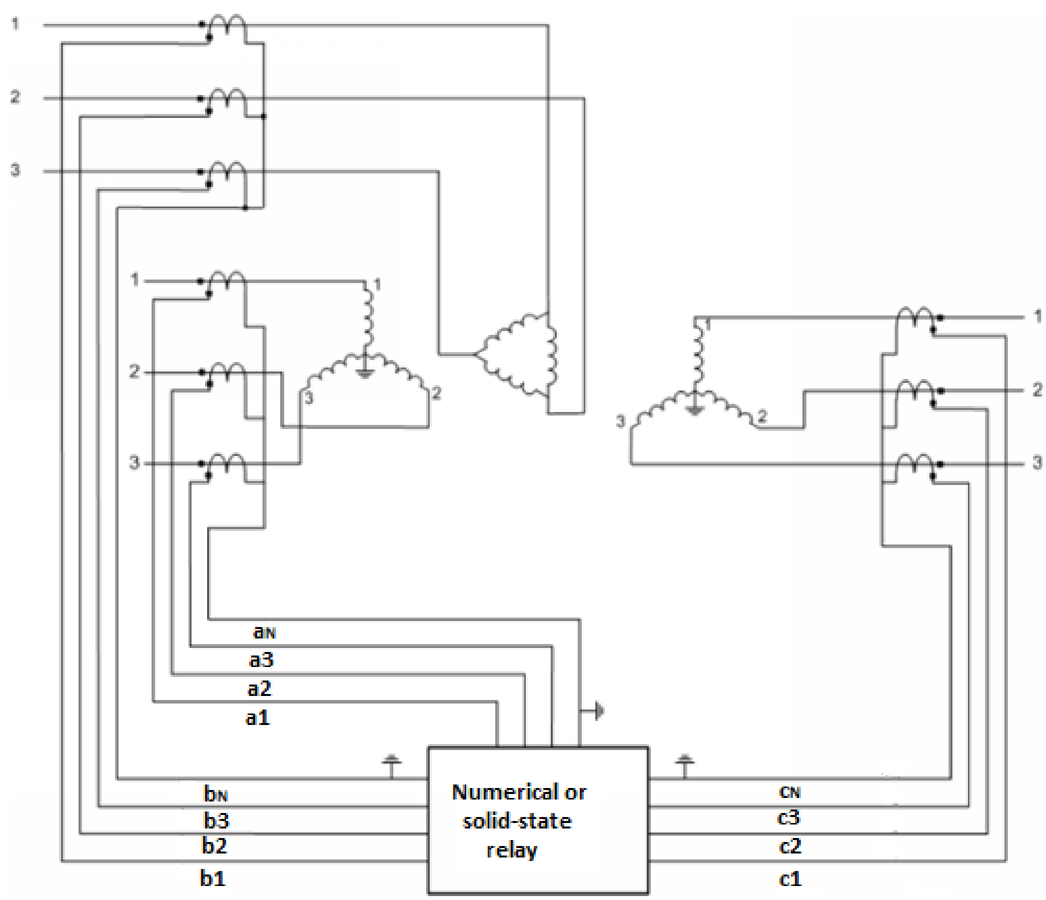


Figure 24: Typical schematic connections for differential protection of a three-winding transformer [30]

Percentage differential relays that are commonly applied for transformer protection may classified as:

- Percent differential relays with restraint actuated by currents going into and out of the protection zone.

- Percent differential relays with restraint actuated by one or more harmonics along with currents going into and out of the protection zone.

Transformer protection schemes at wind electric plants typically utilize percent differential with harmonic restraint and/or blocking. The basis of the percentage differential relay is that the difference current (as measured at the ends of the protected zones) is more than a predetermined percentage of the restraint current. The percentage difference can be fixed or variable (adaptive), based on the relay's design. There is also a minimum differential current threshold before tripping without regard to the restraint current. Details of minimum pickup, restraint current, and characteristic slope vary among manufacturers. Slope may not be a straight line but may curve up depending on the design of the percentage restraint system. This curve allows even larger percentage mismatches during heavy through-currents. These options are shown in Figure 25.

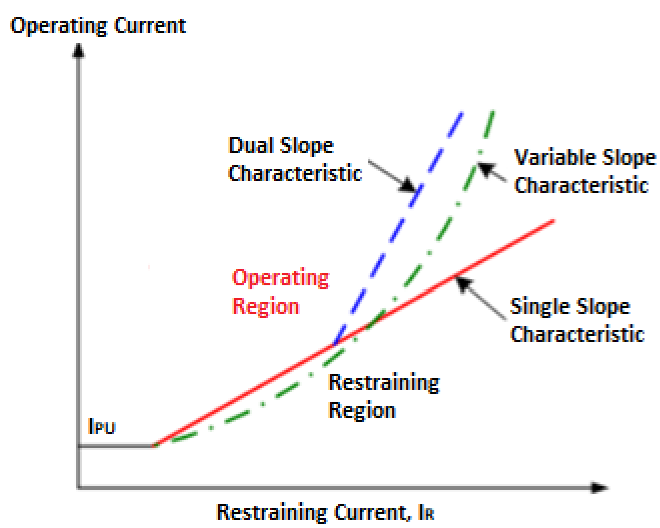


Figure 25: Typical options for the characteristics of percentage differential relays [30]

Modern microprocessor relays employ harmonic restraint and blocking functions to make the scheme more secure during transformer energization. Second and 4th Harmonics restraint or blocking functions can be set as a percentage of the fundamental. These schemes can block the percent differential either independently or utilize cross-blocking. A 5th Harmonic element can be set to alarm for overexcitation conditions. Harmonic blocking and alarm settings may require a more in-depth review at wind farm plants due to additional sources of Harmonics. Wind farm plants could have inverter-based generation (Type 4 Turbines), Capacitor Banks for VAR support, Capacitor Banks with Limiting Current Reactors (Harmonic Filters), and STATCOMs for dynamic VAR support. Harmonic currents can cause overheating and extra losses in many components including transformers. Overheating shortens the useful lifetime of transformers, and in an extreme case, can lead to their destruction. It is important to consider all of these issues when determining the best scheme for harmonic restraint, harmonic blocking, and overexcitation protection.

To successfully detect faults in grounded wye-connected transformer windings, the relay system is designed to discriminate between faults internal and external to the protected zone. The ground differential relay, device 87G in Figure 26, which is typically an overcurrent relay, or the directional ground relay, device 67G connected as in Figure 27, is satisfactory. Both relay schemes will operate correctly for any internal ground faults with the circuit breaker in the circuit to the grounded wye winding being open or closed. They will operate correctly with an external zero-sequence current source, and they will not operate for external ground faults. The auxiliary CT is necessary if the phase and neutral CTs are of different ratio, and the relay is of the electromagnetic or solid-state type. If a numerical relay is used, the auxiliary CT is not needed because the ratio mismatch is taken care of during the computations in the relay. Both schemes are particularly applicable where the ground-fault current is limited, and phase differential relays may not respond. The operating current in device 67G is zero for an external fault with CT ratios matched. Therefore, it is advisable to select the auxiliary CT ratio to give definite non-trip bias to device 67G for an external ground fault (auxiliary CT secondary current slightly greater than the transformer neutral CT secondary current).

Unequal CT currents can produce residual error current during external phase faults. No transformer neutral current is produced, and sensitive relays could operate unnecessarily. Some modern relays allow relay operation only if the current in the transformer neutral exceeds a threshold.

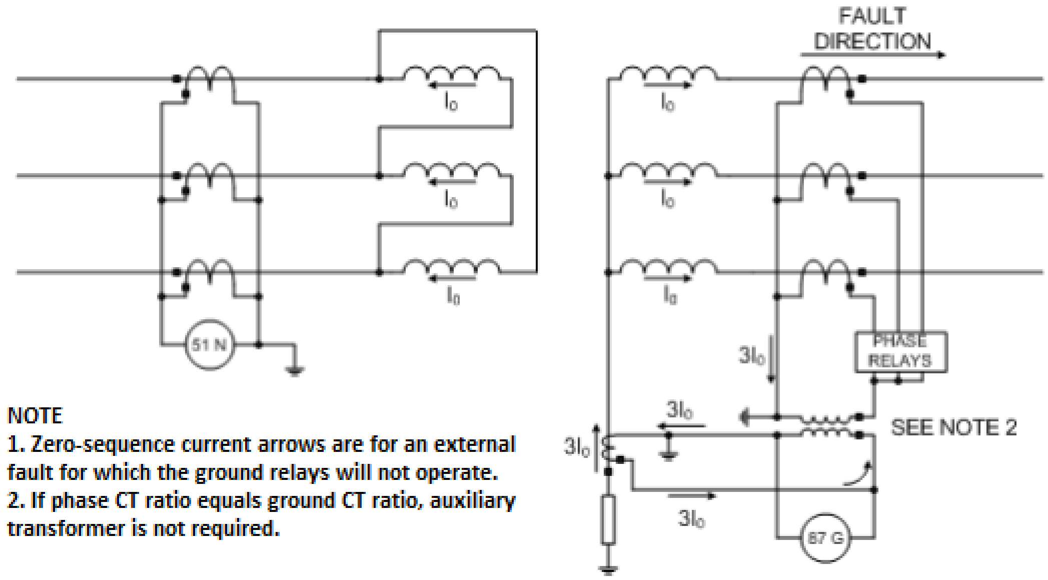


Figure 26: Complete ground-fault protection of a delta-wye transformer using a residual overcurrent and differentially connected ground relay [30]

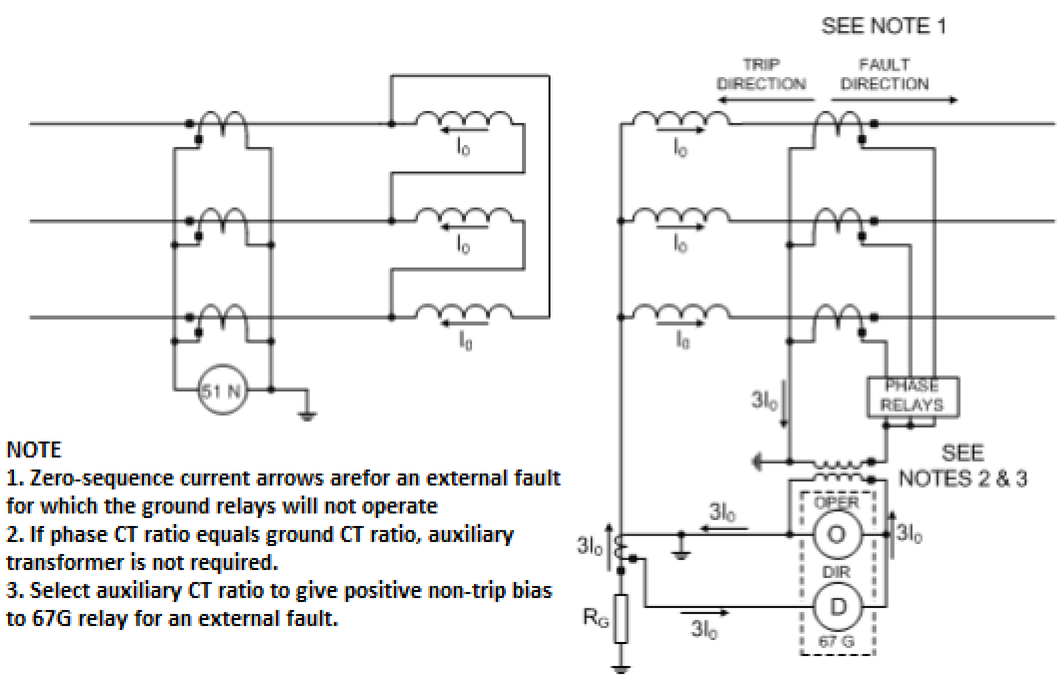


Figure 27: Complete ground-fault protection of a delta-wye transformer using a residual overcurrent and directional relay [30]

3.4.2 Overcurrent Protection and Coordination with Collector Feeders

Instantaneous overcurrent elements can be used for fast clearing of high magnitude internal faults. These elements are normally set above the maximum through fault current for a fault outside the transformer zone of protection. The pickup range is generally 125% - 200% of a three-phase fault on the low side of the transformer. The elements are also set to be secure against transformer inrush. Some wind farm plants may have a weak source. In this case, the instantaneous settings are typically checked to see that they are not set above the maximum available fault current at the station. In these cases, harmonic restrained instantaneous elements may be considered for providing the desired protection.

When setting ground instantaneous overcurrent elements on autotransformers and on three-winding transformers connected wye grounded-wye grounded with a delta tertiary winding, the ground fault current seen by the relay for asymmetrical faults on either side of the transformer will need to be considered. The ground instantaneous element will see need to be set above the higher of the two ground fault current contributions.

Time overcurrent elements are used to protect transformers due to a failure of the protection system to clear an external fault. High through fault current can cause internal, thermal, or mechanical damage to the main transformer. Annex A in IEEE C37.91-2008 Guide for Protecting Power Transformers provides a detailed description to develop the transformer through-fault-duration guide to protect power transformers. Figure 28 shows the category IV transformer damage curves of Figure A.4 from the C37.91-2008 guide.

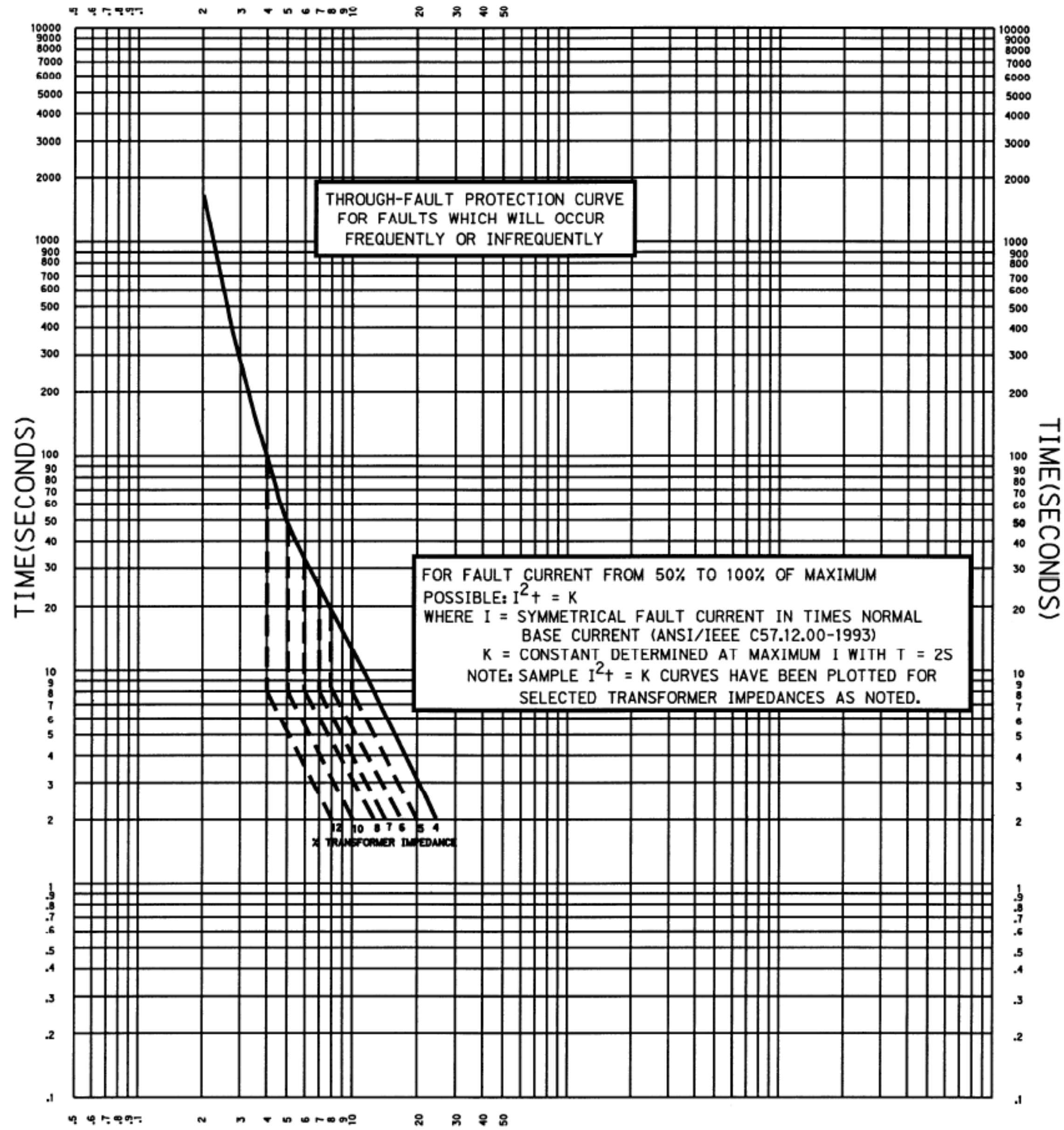


Figure 28: Thermal Damage Curve for Category IV Transformers from IEEE Standard C37.91-2008

The time overcurrent curve, tap, and time dial are selected to coordinate with the transformer damage curve. The tap setting is also selected to carry the transformer load plus a margin for overload. A coordination check will then need to be performed with the collector circuit overcurrent protection. Sufficient margin is typically included to provide adequate coordination between the collector circuit and the main power transformer. Traditional distribution substation feeder circuits supply load, and a check may need to be performed on high impedance faults to account for the additional load current flowing through the transformer in addition to the fault on the feeder circuit. Because collector feeder circuits supply generation back to the station, the situation of the transformer seeing excessive load current in addition to the fault current seen on the collector circuit during a high impedance fault is minimized.

It is important to verify that the current pickup settings of the phase time overcurrent elements also meet any asynchronous generator requirements defined by regulating authorities. For example, PRC-025-1, Table 1 "Relay Loadability Evaluation Criteria [20] requires that overcurrent elements shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the MVAR output of any static or dynamic reactive power devices).

The tertiary winding of an autotransformer, or three-winding transformer, is usually of much smaller kVA rating than the main windings. Therefore, overcurrent relays set to protect the main windings offer almost no protection to these tertiary windings. During external ground faults on the high-voltage or low-voltage side of the transformer, the tertiary windings may carry very heavy currents. Hence, in the event of failure of the primary protection for external ground faults, separate tertiary overcurrent protection may be desirable. The method selected for protecting the tertiary winding generally depends on whether the tertiary is used to carry load. If the tertiary does not carry load, protection can be provided by a single overcurrent relay connected to a CT in series with one winding of the delta-connected winding. This relay will sense system grounds as well as phase faults in the tertiary or in its leads.

If the tertiary winding is used to carry load, partial protection can be provided by a single overcurrent relay supplied by three CTs, one in each winding of the delta and connected in parallel to the relay. This connection provides only zero-sequence overload protection and does not protect for positive- and negative-sequence overload currents. In this case, the relay will operate for system ground faults but will not operate for phase faults in the tertiary or its leads. Where deemed necessary, separate relays, such as differential type, may be provided for protecting against phase-to-phase faults in the tertiary windings or its leads.

The setting of the overcurrent relays, which are provided for protecting the tertiary windings, can normally be based on considerations similar to the other overcurrent elements. However, three CTs (one in each phase) can be connected in parallel to provide zero-sequence currents to an overcurrent relay; this relay can be set below the rating of the tertiary winding. Be aware that this relay is still required to be set to coordinate with other relays on the system.

When tertiary windings are connected by cables, the overcurrent protection provided for the tertiary winding is typically set to account for the thermal withstand capability of the cables. Alarming and tripping resulting from a prolonged unbalance condition or LTC malfunction will therefore prevent damage to cables.

Below are example calculations and coordination curves for one of the two main power transformers of a theoretical wind farm plant. The theoretical wind farm plant has the following specifications:

- Total Size = 300 MVA
- Number of Transformers = 2. Each transformer:
    - 3 Winding
        - Wye, Wye, Delta
    - 138:34.5kV
    - 134/178/222 MVA
    - Z = 11.2% @ 134 MVA
- Voltage = 138:34.5kV
- Total Number of Wind Turbine Generators = 88 (44 WTGs supply each main low-side bus)
- Size of Type 3 Wind Turbine Generators = 3.4 MVA
- Studies indicated that no additional VAR support was required for the installation.

Example Phase Instantaneous Overcurrent – 50P. 50P is generally set for the higher of the following conditions: 1.3 – 1.5 times a low side three phase fault or 8 – 12 times the transformer nameplate rating to account of inrush current. In our example, a three-phase fault on the 34.5 kV bus produces 3125 A on the 138 kV side of the transformer.

$$50P_{HS} = 1.5 \times 3125A = 4687.5A_{PRI} \text{ or } 50P_{HS} = 12 \times \frac{134MVA \times 1000}{\sqrt{3} \times 138kV} = 6727A_{PRI}$$

$$51P_{HS} = 1.5 \times I_{FLA} = 1.5 \times \frac{150MVA \times 1000}{\sqrt{3} \times 138kV} = 1.5 \times 627A = 941A_{PRI}$$

$$51P_{LS} = 1.5 \times I_{FLA} = 1.5 \times \frac{150MVA \times 1000}{\sqrt{3} \times 34.5kV} = 1.5 \times 2510A = 3765A_{PRI}$$

HS CTR = 1200:5 or 240:1

LS CTR = 4000:5 or 800:1

$$50P_{LS} = \frac{6727A_{PRI}}{CTR} = \frac{6727A_{PRI}}{240} = 28.2A_{SEC} \approx 28A_{SEC}$$

$$51P_{HS} = \frac{941A_{PRI}}{CTR} = \frac{941A_{PRI}}{240} = 3.92A_{SEC} \approx 4A_{SEC}$$

Full load current of 44 WTGs is 626 A. Per regulatory standards (PRC-025 [20]), the phase time overcurrent pickup can be set greater than or equal to 130% of the maximum aggregate WTG nameplate output. 1.3 x 626 A = 814 A. Therefore, a $51P_{HS}$ current pickup setting of 4 = 960 A, primary will satisfy PRC-025. The same will be true for the $51P_{LS}$ current pickup setting.

$$51P_{LS} = \frac{3765A_{PRI}}{CTR} = \frac{3765A_{PRI}}{800} = 4.7A_{SEC} \approx 4.7A_{SEC}$$

The resulting coordination between the collector feeder and collector station main power transformer overcurrent relays appears in Figure 29.

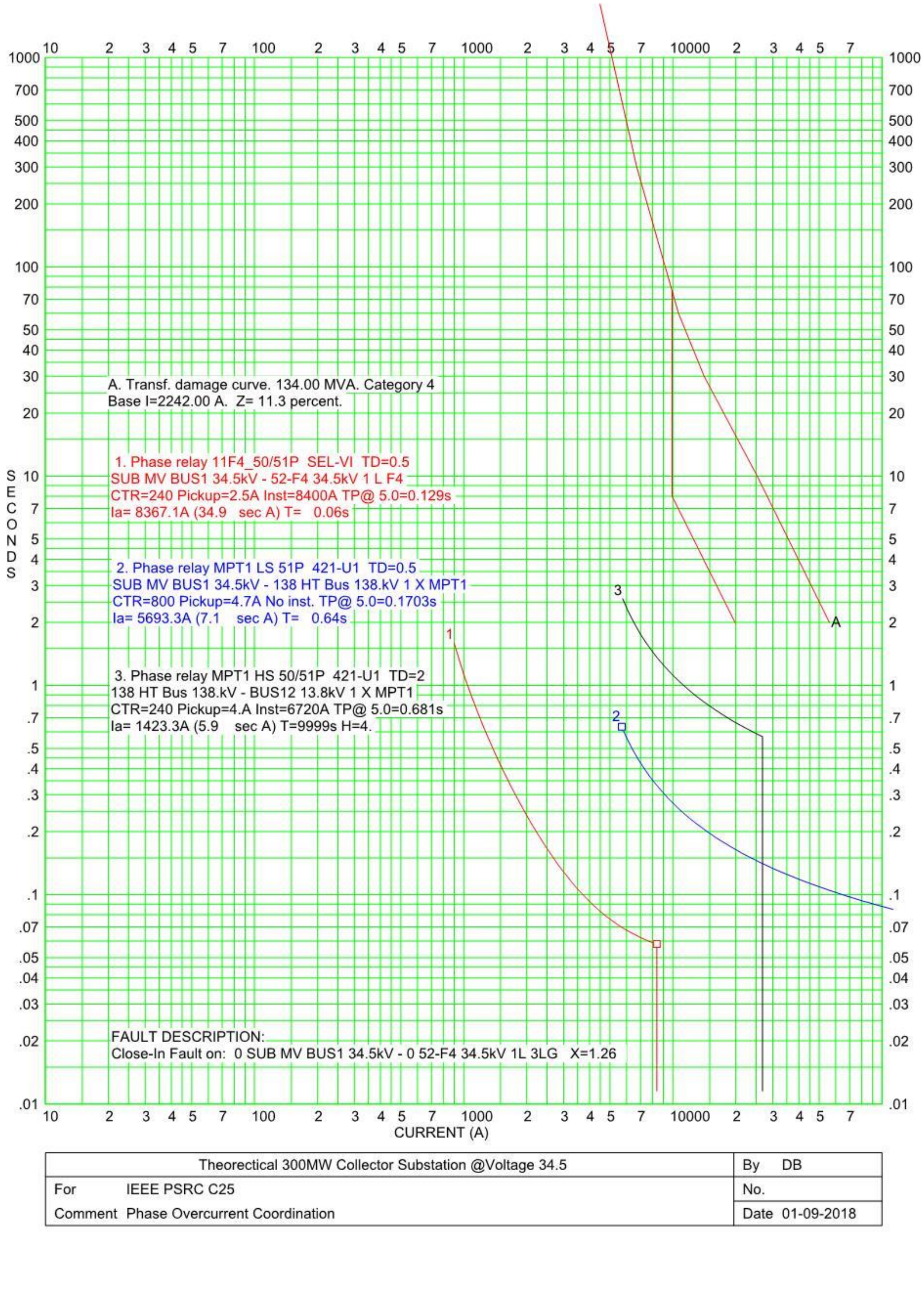


Figure 29: Main Transformer Phase Overcurrent Coordination

3.4.3 Mechanical Detection of Faults

Some transformer faults go undetected when differential and overcurrent schemes are used. A turn-to-turn fault can cause considerable current to flow in the shorted turn, while current in the remaining winding remains relatively unchanged. Since there is little or no change in the current monitored by the CTs, there is no differential current for the relays to operate. If the turn-to-turn fault either evolves to include more turns or evolves into a ground fault, then the differential elements may be able to operate for the change in current.

There are two methods of detecting transformer faults other than by electric measurements. These methods are as follows:

a) Accumulation of gases due to slow decomposition of the transformer insulation or oil. These relays can detect heating due to high-resistance joints or due to high eddy currents between laminations.
b) Rapid increases in tank oil or gas pressures caused by internal transformer faults.

The mechanical pressure relays come in a variety of types. Depending on the configuration of the transformer, the application will vary. A sudden-oil-pressure relay can be applied to any oil-immersed transformer. It would be mounted on the transformer tank wall below the minimum liquid level. If an internal fault develops, the rapid rise in oil pressure or pressure pulse is transmitted to the silicone oil by way of the transformer oil and the bellows. This then acts against the piston, which closes the air gap and operates the switch. A similar type of mechanical pressure relay can be applied to monitor the gas pressure above the oil. There is also a type of relay, commonly known as the Buchholz relay, which is applicable only to transformers equipped with conservator tanks and with no gas space inside the transformer tank. It will operate for small faults by accumulating the gas over a period of time or for large faults that force the oil through the relay at a high velocity.

These devices can detect a small volume of gas produced by low-energy arcs, overheating, and insulation decomposition. For example, when high current passes through a shorted turn, a great deal of heat is generated. This heat, along with the accompanying arcing, breaks down the oil into combustible gases. Gas generation increases pressure within the tank. A sudden increase in gas pressure can be detected by a sudden-pressure relay either located in the gas space or under the oil. The sudden-pressure relay usually operates before other relays sensing electrical quantities thus limiting damage to the transformer. The accumulator portion of the relay is frequently used for alarming only; it may detect gas that is not the result of a fault, but that can be evolved by gassing of the oil during sudden reduction of pressure. This relay may also detect heating due to increased power transfer, increased ambient temperature, full or partial failure of the cooling system, high-resistance joints, high eddy current between laminations, low- and high-energy arcing, or accelerated aging due to overloading.

One drawback to using a sudden-pressure relay is its tendency to operate on high-current through-faults. Various methods to prevent undesired operation have been developed. The most common method uses an instantaneous overcurrent relay to supervise the sudden-pressure relay, whereby taking advantage of the fact that a close-in through-fault creates a high current in the transformer. Another method, used less often, is to place sudden-pressure relays on opposite corners of the transformer tank. Any pressure wave due to through-faults will not be detected by both sudden-pressure relays. The contacts of the sudden-pressure relays are connected in series so that the operation of both relays will provide a genuine sudden pressure trip output.

3.5 Capacitor and Harmonic Filter Protection

Protection schemes applied to capacitors and harmonic filters at the main collector substation are essentially the same as those applied at conventional substations. The primary purpose of the protection scheme is to take the protected equipment out of service for faults. IEEE Standard C37.99: IEEE Guide for the Protection of Shunt Capacitors [31] provides detailed information on the application and setting of protective relays for shunt capacitors. Similarly, IEEE Standard C37.109: IEEE Guide for the Protection of Shunt Reactors [32] provides detailed information on the application and setting of protective relays for shunt reactors. While C37.109 does not directly address the protection of the reactors used in harmonic filters, the protection schemes presented are also applicable to the reactors used in harmonic filters as well.

3.5.1 Voltage Protection

Two levels of undervoltage and overvoltage settings are typically applied for capacitor protection. For example, a Level 1 undervoltage setting of approximately 90% of nominal voltage and a Level 2 undervoltage setting less than or equal to 45% of nominal voltage may be applied. Similarly, a Level 1 overvoltage setting of approximately 110% of nominal voltage and a Level 2 undervoltage setting of approximately 120% of nominal may be applied. Appropriate undervoltage delay settings are selected based on the desired "ride-through" time for a system undervoltage condition. Appropriate overvoltage delay settings are chosen either on the desired ride-through time for a system overvoltage condition or on the maximum overvoltage withstand capability of the capacitor units.

For shunt capacitors at collector feeder substations, the voltage protection settings are also coordinated with the voltage protection settings that are applied to the WTGs. Ideally the capacitor voltage protection settings are delayed long enough to allow the WTG voltage protection equipment to take the WTG off-line before the capacitor breaker or circuit switcher at the collector feeder substation trips.

3.5.2 Overcurrent Protection

Overcurrent protection schemes are typically applied to trip shunt capacitors or harmonic filters for both phase and ground faults in the equipment. Instantaneous overcurrent elements are set based on the maximum expected inrush current, and time overcurrent elements are set based on the maximum current rating of the capacitor or reactor. The instantaneous element may require a short delay to provide proper coordination with the expulsion fuses on the capacitor cans. Inverse time curves are normally used for time overcurrent applications, and the time dial is selected to coordinate with both the capacitor can fuses and any “upstream” time overcurrent relays such as the backup time overcurrent relays associated with the main power transformer at the collector substation. When overcurrent relays are used for capacitor or harmonic filter protection, the presence of harmonics may require the use of relays equipped with RMS based current detectors capable of measuring both fundamental and harmonic currents.

3.5.3 Harmonic Current and Voltage Considerations for Protection Scheme Operation

It is important to assess the effect of connecting WTGs to the electric utility’s power system prior to their installation to verify that the system harmonic and voltage limits required by the utility can be achieved. The electrical characteristics of the wind turbines are required to assess the effect of the WTGs on the system. Given the manufacturer’s typical electrical characteristics for the WTGs installed at the wind electric plant site, the combined impact of the WTGs on voltage quality can be calculated.

Inverters connected to WTGs can cause harmonics [4]. The order and magnitude of the harmonic currents depend on the technology of the converter and the mode of operation [6]. The voltage waveform can be distorted by the injection of harmonic currents, which can propagate throughout the distribution grid. Furthermore, small voltage distortions can cause large harmonic currents from series resonance conditions between the cable capacitance and the supply inductance (transformer leakage and cable inductance). Harmonic currents arising from the interaction between the WTGs and the grid can become worse over time due to several factors:

- The wind farms become bigger, and therefore the source impedance may increase.

- The equivalent capacitance increases due to use of long extra high voltage cables where the operators cannot obtain the necessary right of way for an overhead line.
- The use of large wind electric plant transformers on the grid.
- The use of switched capacitors and reactors on the grid.
- Increased harmonic voltage distortion over the years.
- Very low resistive losses in the site design to optimize power production.

All these factors together represent a general reduction of the resonant frequency into areas where network and WTG harmonic currents exist to excite it (from 5^{th} to 15^{th} harmonic order). In addition, a small harmonic current can create high levels of voltage distortion, and a low series resistance can produce a very high magnification factor. Finally, the source impedance will vary because the wind electric plant is a combination of many individual WTGs, which shifts these resonant frequencies over a range as the WTGs connect and disconnect. Consequently, the identification and elimination of possible resonance conditions during the initial design of the wind electric plant has become very important.

The spectrum of harmonic currents is a problem because it can increase the voltage harmonic levels over many harmonic and inter-harmonic frequencies and phase angles. Sometimes the difference between the calculated harmonic values used during planning and design and the actual values observed in the field do not become apparent until unforeseen harmonic issues crop up after the wind electric plant goes into service. Harmonic levels may be normal most of the time but on some occasions, they may exceed agreed standards. In these cases, some of or all the WTGs may automatically shut down from the operation of their internal harmonic protection schemes. It is desirable to avoid such operation if possible because it requires manual intervention to restart the WTGs, leading to high levels of lost production.

Voltage flicker may also be seen on WTG collector feeder system. For example, the tower effect of a fixed speed WTG can cause voltage flickers due to the wind shielding effect of each blade of a three-blade turbine as it passes the tower. The injected electrical power of the WTGs is reduced when the blade passes the tower, which affects the grid voltage [6]. As the blade passes by the tower it causes a power oscillation and voltage flicker at a frequency of three times the blade turning speed. Alternatively, the presence of several WTGs distributed on the collector feeder may reduce the network impedance of the system. As a result, the changing load current will lead to a smaller voltage variation due to the changing load and hence improved power quality [8].

3.6 Transmission Tie Line Protection

Transmission tie line protection faces two challenges that are different from conventional transmission interconnections to generating stations.

a) Variability of source strength due to variability of wind. This means that variable zero, positive and negative sequence source strength may be considered a normal operating condition. Additional contingencies may need to be taken into consideration when applying or setting transmission line protection systems.
b) Short circuit current contribution will likely be controlled as to magnitude and power factor.

With respect to the variability of source strength, the various sequence networks may be considered separately. Due to lack of wind, all machines may be at standstill under normal conditions, and all machines may be off-line. Reactive power compensation devices (if applied) may be on or off-line. Thus, positive and negative source impedances may be so high as to cause the source strength to be considered negligible. Zero sequence source impedance however will be provided by ground paths through the interconnecting power transformer(s). If there is only one interconnecting transformer, a single contingency may result in it being out of service. In effect then the wind plant will be off-line. This contingency may be considered as the wind plant terminal being open. If there is more than one interconnecting transformer, a single contingency may result in one of the transformers being out of service. The line protection then would be designed to be suitable for infinitely high positive and negative source impedance and higher than normal zero sequence source impedance.

With respect to the controlled nature of the short circuit contribution additional considerations become necessary. Most controlled sources will limit the magnitude of short circuit current contribution to not more than 150% of rated current. But for most WTGs to meet the low voltage ride through required by the grid codes, the limit on the magnitude of short circuit current contribution does not take place for a few cycles into the fault. Depending on the speed of operation for the line relays, the short circuit current contribution from the wind plant for a line fault maybe significantly higher than the limited value [24]. This means that instantaneous phase overcurrent protection devices may be useful, but that phase time overcurrent protection devices will be of little use. The controlled nature of the short circuit contributions also means that the negative sequence current contribution to unbalanced faults may be intentionally limited to negligible levels. This is true for the current design for the Type 4 WTG [1]. This means that negative sequence current supervision of directional functions may also be of little value [24]. Further, the reactive reach of quadrilateral distance elements that depend on conventional inductive phase or negative sequence current sources may also perform unreliably and may over or underreach [24],[25].

3.6.1 Typical Communications Assisted Protection Schemes

Typical communications assisted protection schemes may be divided into three classes: directional comparison, phase comparison and line current differential. They will be discussed separately.

Directional comparison schemes often used distance relays and may depend on underreaching or overreaching distance functions as well as directional overcurrent functions. As noted above, low fault current contributions may reduce the dependability of distance functions due to current supervision functions failing to assert. Also, as noted in [25], the reach accuracy of quadrilateral functions is highly dependent on the control settings in the converter equipment. If control settings are set to minimize or reduce negative sequence current contributions to unbalanced faults, then negative sequence directional elements may also be unreliable. Since interconnection transformers usually have a path for ground current flow, and since this path will be highly inductive, zero sequence directional functions will often be more reliable than negative sequence directional functions. To cover for cases with little or no wind, weak source echo functions would often be helpful if permissive overreaching transfer tripping (POTT) logic is used. In all cases of directional comparison logic, direct transfer tripping from the (normally strong) utility terminal of the interconnection would be an important supplement.

Phase comparison schemes need a minimum amount of current from both terminals to have sufficient current to provide reliable phase angles. In view of the possible minimal current from a wind plant, especially in faults not involving ground, phase comparison schemes are usually not applicable.

Line current differential protection schemes do not need strong sources from both terminals, and typically will provide the most reliable interconnection transmission line protection. Of course, these schemes require high bandwidth communications facilities.

3.6.2 Back-up Protection Schemes

As noted in the previous section, direct transfer trip is an important supplement to directional comparison schemes. This direct transfer trip may indeed be the primary protection for the wind plant terminal and could be applicable whether or not directional comparison line protection is provided.

As backup protection, time delayed undervoltage protection on all three phases will provide dependable tripping of the wind plant terminal even under weak or no source conditions. Undervoltage protection is not very selective, so time delays on the order of several seconds may be required to coordinate with slowly cleared faults on other parts of the system. However, high speed tripping of a weak source like a wind plant is not normally required unless there could be a power quality problem for loads islanded with the wind plant.

3.6.3 Voltage and Frequency Protection Requirements

Voltage and frequency protection may be required under certain circumstances. At the point of interconnection to the transmission network, relay elements to monitor and force the disconnection of the wind plant for out-of-normal range of operation may be required by the transmission provider. Typically, multiple steps of level detection for both voltage magnitude and frequency for under and over conditions are applied. The more out-of-tolerance the conditions are, the shorter the time delay to the tripping [26]. The elements that pick up closer to the normal range are more for power quality protection and operate with enough delay to permit the controls at the wind plant to return system conditions back to normal before the trip. Experience has shown that the most likely reason for the operation of these relay elements are for failure of voltage control elements at the wind plant; however, the isolation of wind plants with blocks of load has also occurred due to transmission system outages. For these events the wind plants are not able to maintain acceptable voltage and frequency, which can result in the damage of load equipment if the wind plants are not forced to disconnect after the normal fault ride-through requirement period. The elements that pick up for the more extreme conditions are set to protect the transmission provider's and other customers' equipment from damage. Direct transfer tripping of the wind plant for isolation of the transmission interconnection from the plant to the to the integrated system may also be considered for fast protection of other tapped loads from unacceptable voltage or frequency excursions.

An important consideration with respect to overvoltage is whether the wind plant is an effectively grounded source. In some cases, wind plants may be connected without an effective neutral ground connection [26]. In those cases, temporary overvoltage on un-faulted phases during ground faults may be a concern. In such cases delayed tripping of the utility terminal (until after the wind plant has tripped) may be required for ground faults and sacrificial surge arresters may be used as backup protection.

As noted in Section 3.6.2, time delayed undervoltage protection may provide effective backup protection for the wind plant terminal of the interconnected line.

3.6.4 Supervision Requirements for Transmission Line Breaker Closing

The wind plant, like any other generation plant cannot be connected asynchronously to another system. Therefore, three phase undervoltage supervision would be employed to verify that all three phases of the line are dead before automatically reclosing a transmission line breaker from the utility side. However automatic reclosing of an overhead transmission line from the utility side (with the wind plant side breaker open) could be a useful test of the line. Once the line was tested satisfactorily from the utility, the wind plant could be reconnected in the normal manner.

4 Conclusion

This report provides an overview of the protective and system requirements for wind power plants, which can be unique and challenging due to the following:

- Wind power plants are different from conventional generation in that there are typically numerous relatively small wind turbine generators (WTG) distributed geographically over a wide area.
- The WTGs predominantly in service have some degree of inverter interface. This affects the fault current levels and characteristics which protection engineers have come to expect from sequence analysis.
- Some WTGs operate with a slip. When near transmission systems employing series compensation, this can result in sub-synchronous interactions.
- There are various types of electrical layouts and grounding options depending on the grid the wind power plant is connected to.
- It is important to consider applicable regulatory requirements, such as low-voltage ride through (LVRT), to enable the wind power plant to assist the grid during contingencies. Maintaining adequate power quality is another such consideration.

Various protection elements have been used in practice to address many of the afore-mentioned issues successfully. These elements are discussed in this report with setting guidance to aid the protection engineer meet the general protective requirements of wind power plants. Additional system studies may be required to address complex conditions such as sub-synchronous interactions. As the penetration of wind power plants in our system increases, the challenges and protective considerations continue to evolve. The protection engineer will benefit from further reading to understand the present best practices.

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APPENDIX A : Directional Phase Overcurrent Setting Considerations for WTG Operation

Figure A1 shows the current characteristic of WTG Types 3 and 4. As shown in this figure, when the WTG current lags its terminal voltage (Figure A1 left, blue region) or the feeder current as measured by the 67P leads its measured voltage (Figure A1 right, blue region), the WTG supplies reactive power to the system. This occurs when the collector system experiences low voltage, and most probably the collector system is heavily loaded. Hence, the WTG power control system will operate to make the WTG behave like a capacitor to raise the voltage. Figure A2 shows the directional element (67P) characteristic on an R-X plot with the forward trip direction of the 67P set towards the WTGs on the collector circuit. For the afore-mentioned condition, the impedance seen by the 67P element falls within the blue region i.e. third and fourth quadrants in Figure A2. If the power generated by the aggregate WTGs exceeds the aggregate station service and power loss (P_{Aux}) in the collector system, then the impedance seen by the 67P falls within the third quadrant, which is completely outside the tripping region. Conversely, if the power generated by the aggregate WTGs is less than P_{Aux}, the impedance seen by the 67P falls within the fourth quadrant, which encompasses part of the tripping region. For the seen impedance to fall within the tripping region in the fourth quadrant, the WTG will supply a very small reactive power as well as an active power less than P_{Aux}. As it is confirmed through simulation later in this section, this results in a current supplied by the aggregate WTGs that is less than the 67P pickup setting; consequently, it is of no concern.

As shown in Figure 15 A1, when the WTG supplying current leads its terminal voltage (Figure A1 left, red region) or the current measured by the 67P lags its measured voltage (Figure A1 right, red region), the WTG absorbs reactive power. This occurs when the collector system experiences high voltage, and as mentioned earlier, most probably the collector system is lightly loaded. In that case, the WTG power control system will operate to make the WTG behave like an inductor to lower the voltage. For the afore-mentioned condition, as shown in Figure 16A2, the impedance seen by the 67P element falls within the red region i.e. first and second quadrants. If the power generated by the WTGs exceeds P_{Aux}, then the impedance seen by the 67P falls within the second quadrant, which partially covers the tripping region. On the other hand, if the power generated by the aggregate WTGs is less than $P_{Aux,}$, the seen impedance falls within the first quadrant, which completely encompasses the tripping region. In the tripping region, there are certain areas where the measured current will not exceed the pickup setting, while there are cases where the current may exceed the 67P pickup setting, resulting in a false trip. To better learn and investigate these cases, a simulation study was performed, and the results are presented in Figure A3.

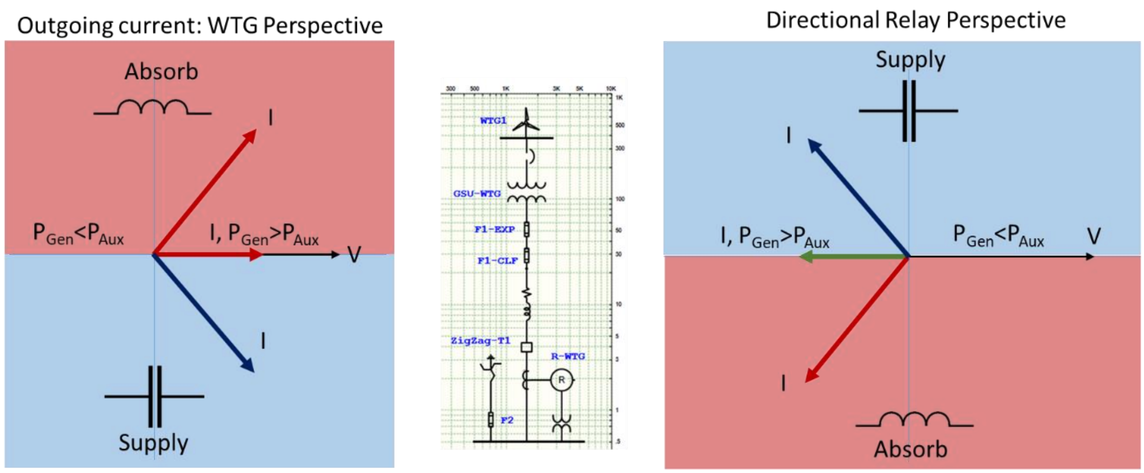

Figure A1: Fault Current Characteristic of WTG Types 3 and 4

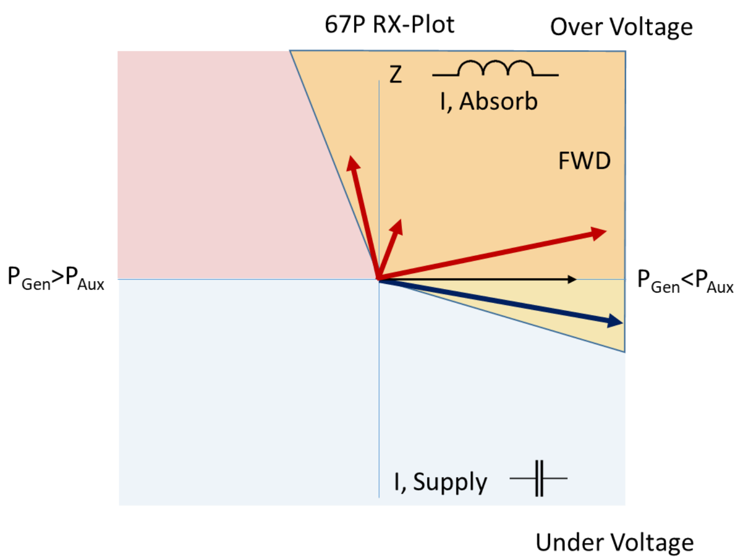

Figure A2: 67P Characteristic RX-Plot

Figure A3 shows the seen impedances as measured by the 67P element protecting a wind farm collector for 11 simulation cases [22]. In the first eight cases, the voltage was varied from 0.95 pu to 1.1 pu while the WTG active power generation was almost zero, and P_{Aux} was about 10% of the WTG rated power with a power factor of 0.85 lagging. In addition, the 67P pickup setting was set to 120% of the entire collector WTG rated auxiliary power. As shown in this figure, when the collector main bus voltage was forced to voltages such as 0.95 pu or 0.97 pu, the impedance seen by the 67P fell into the fourth quadrant outside of the typical directional characteristic region. Hence, it was not of any concern. For voltages between 1 pu and 1.06 pu, the impedance seen by the 67P fell within the directional characteristic in the first quadrant. However, as the current value was below the pickup setting, the 67P element did not pick up. For voltages equal or above 1.07 pu, the absorbed reactive current by WTGs exceeded the pickup setting, and the 67P element falsely tripped.

Four more cases were also simulated where the active power generated by the WTG exceeded P_{Aux}. As shown in Figure A3, the 67P falsely tripped for the cases of V=1.1 pu, Pg=25% and V=1.08 pu, Pg=50%. For the case of V=1.03 pu, Pg=25%, the seen impedance fell within the forward region, although the 67P did not trip because the current measured by the relay was less than the pickup setting. As illustrated in the same figure, the 67P seen impedance angle exceeded 120° and fell outside of the 67P characteristic for V=1.04 pu and Pg=60% while the measured current was above the pickup setting. In conclusion, the combination of very high overvoltage and medium to very low active power generation will increase the risk of false trips by the 67P element.

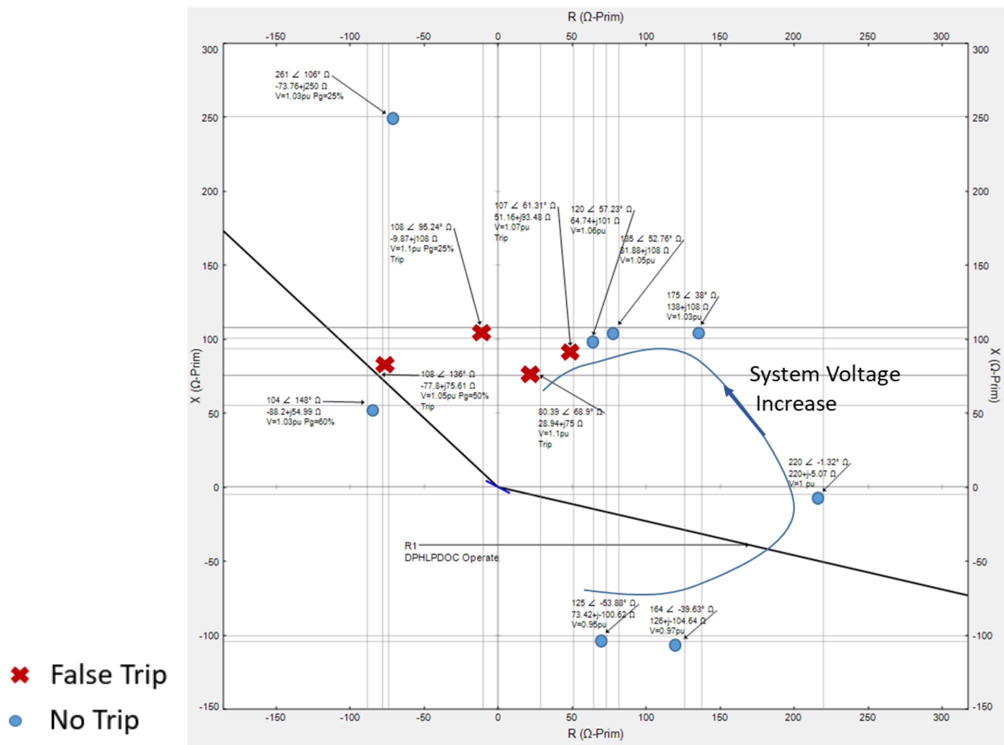

Figure A3: 67P Seen Impedance and Trip Status for 11 Simulated Cases

One solution to minimize the potential of false tripping of the 67P element is to contract the directional characteristic, as shown in Figure A4. This solution eliminates any false trip for cases in which the impedance seen by the 67P is within the second quadrant where the collector wind power generation exceeds P_{Aux}. However, the 67P element may still trip in the extremely rare case of very small power generation close to zero combined with a very large overvoltage of more than 6% on the collector bus.

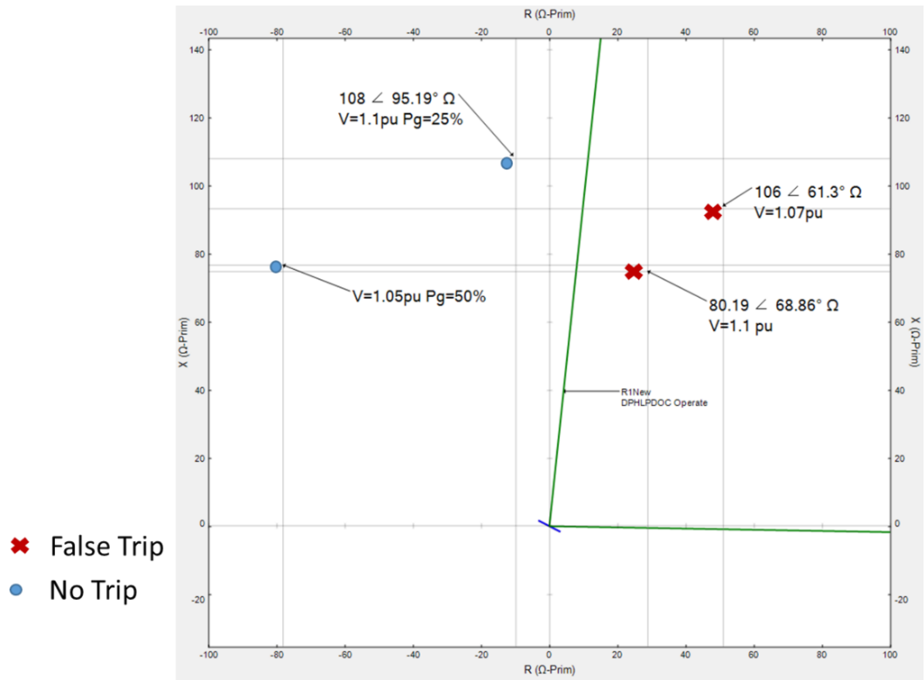

Figure A4: Secure directional element by contracting the directional characteristic

Similar to the first solution, as illustrated in Figure A5, the use of load encroachment eliminates any false trip for cases in which the impedance seen by the 67P are in the second quadrant (if the reverse load encroachment angles are set to 90° and 270°) and where the aggregate WTG power generation exceeds P_{Aux}. However, the 67P element may still trip in the extremely rare case of very small power generation close to zero combined with a very large overvoltage of more than 6% for the simulated system.

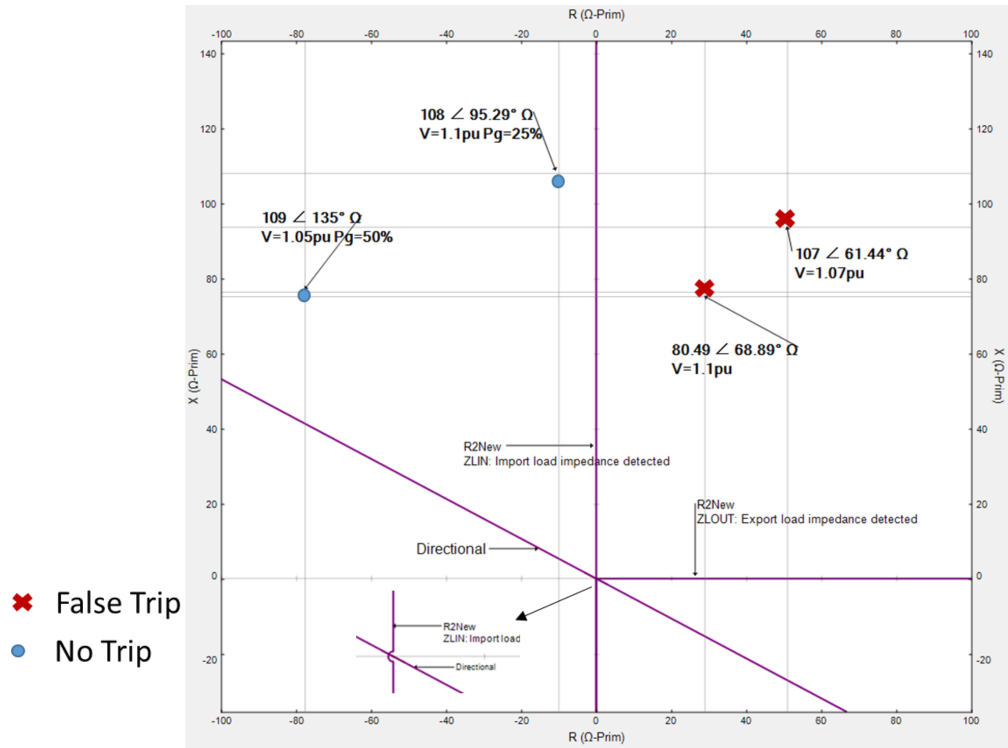

Figure A5: Secure directional element by a load encroachment element (Simulation Results)