Fault Current Contributions from Wind Plants

A report to the

Transmission & Distribution Committee

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Power System Relaying Committee

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IEEE Power and Energy Society

Prepared by the Joint Working Group

Assignment: To characterize and quantify short circuit current contributions to faults from wind plants for the purposes of protective relaying and equipment rating, and to develop modeling and calculation guidelines for the same.

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1. Introduction

The safe, reliable operation of electrical power systems requires the ability to predict and model the sources of fault current, including contributions from wind powered generating plants, in order to select equipment properly rated for the required duty and to properly set protective relays for selective operation. Groups of wind turbine generators are clustered and networked to form wind plants of varying power delivery capability. Several characteristics are unique to wind plants, but the most significant characteristic to the topic of this report is the response of the wind turbine generators to faults on the power system. Wind turbine generators (WTG) must be able to tolerate rapid fluctuations in wind speed (turbulence and gusting), as well as optimize the blade tip speed ratio and thus maximize energy capture. The turbines must be capable of operating at variable speeds, rather than the traditional solid mechanically and electrically connected synchronous generator.

There are wind turbine generators of five basic types that can, in some cases with supplemental equipment, tolerate the fluctuations in the wind speed and deliver electrical power in the form that meets the requirements of the transmission system:

- Type I, squirrel cage induction generator,
- Type II, squirrel cage wound rotor induction generator with external rotor resistance,
- Type III, double fed asynchronous generator,
- Type IV, full power converter generator, and
- Type V, synchronous generator mechanically connected through a torque converter.

This report describes general consideration for wind plant design in section 2. Both theoretical and experimental performance during faults of these five types of wind turbine generators as individual generators and as networked wind plants are described in section 3. Section 4 covers issues for the specification of fault interrupting devices and guidelines for designing protective relay systems for wind plants are presented in section 5. Data necessary for appropriate modeling of individual generators and wind plants is described in section 6. Several actual performance examples are described in section 7.

2. Wind Power Plant Design

In today's competitive wind energy environment, the designs of wind power plants (WPP) and interconnecting substations are not created equal. As a result, each WPP, commonly referred to by the wind community as a collector system, is a complex engineered system.

Some of the factors that affect wind plant electrical design for interconnecting substation(s)/switchyard(s) and the associated collector system are: interconnection lines and facilities, environment, available equipment logistics and lead times, grounding and arc flash, reactive compensation, power quality, harmonics, surge protection, protection and control devices, communications, transformers, and fault ride through requirements, to mention a few. All of these factors greatly affect the resulting design of a WPP which will typically be developed through a fast paced process, while considering electric power system design standards such as NEC, NESC, IEEE, ANSI, NERC, IEC, etc.

While these standards offer significant insight and guidance into the engineering design, planning, protection, control, operations, and maintenance in WPPs, significant gaps still exist. Equivalent electrical models have been developed for WTG, but have achieved limited use within the electric utility industry. Many of the WTG control system designs are proprietary, making general application for modeling more problematic. The lack of models in commercial based software requires that designers make assumptions on the event-based operations of WTGs, which leads to inaccuracies. Much work is needed to address the time domain characteristics of the dynamic nature of these machines. While significant knowledge on large conventional induction machines exists (i.e. it is a simple task to calculate the fault current contribution from an induction machine, as described in Section 3 for the five WTG types) very little is known about the complex nature within the various configurations of individual wind turbines and the aggregate impact on the wind plant and utility for different fault types.

2.1. Interconnection of Utility and Wind Power Plants (WPP)

Wind plants are typically interconnected to existing infrastructure via radial lines, three terminal taps, switchyards, and substations. The interconnection equipment decisions are justified depending on the existing voltage levels, electrical losses, rights of way and easements, environmental concerns, economics related to conductors and land, as well as dependability and security.

Typical configurations of switchyards for WPPs include single bus, sectionalized bus, double breaker bus, ring bus, and breaker-and-a-half bus as shown in Figure 2-1. These configurations can be found in IEEE Std 666™ - 2007, IEEE Design Guide for Electrical Power Systems for Generating Stations, which contains the various bus configurations for generating stations. The more commonly used configurations are the single bus, ring bus, and breaker-and-a-half. IEEE 666 is a useful reference as it covers everything from basic design considerations (safety and reliability) to fault considerations of rotating machines. IEEE Std 605™- 2008, IEEE Guide for Bus Design in Air Insulated Substations should also be consulted, as it is a guide to rigid bus structures with some discussion on “high” wind areas. The choice of HV bus arrangement is related to the cost versus reliability needs of the WPP and the interconnecting utility.

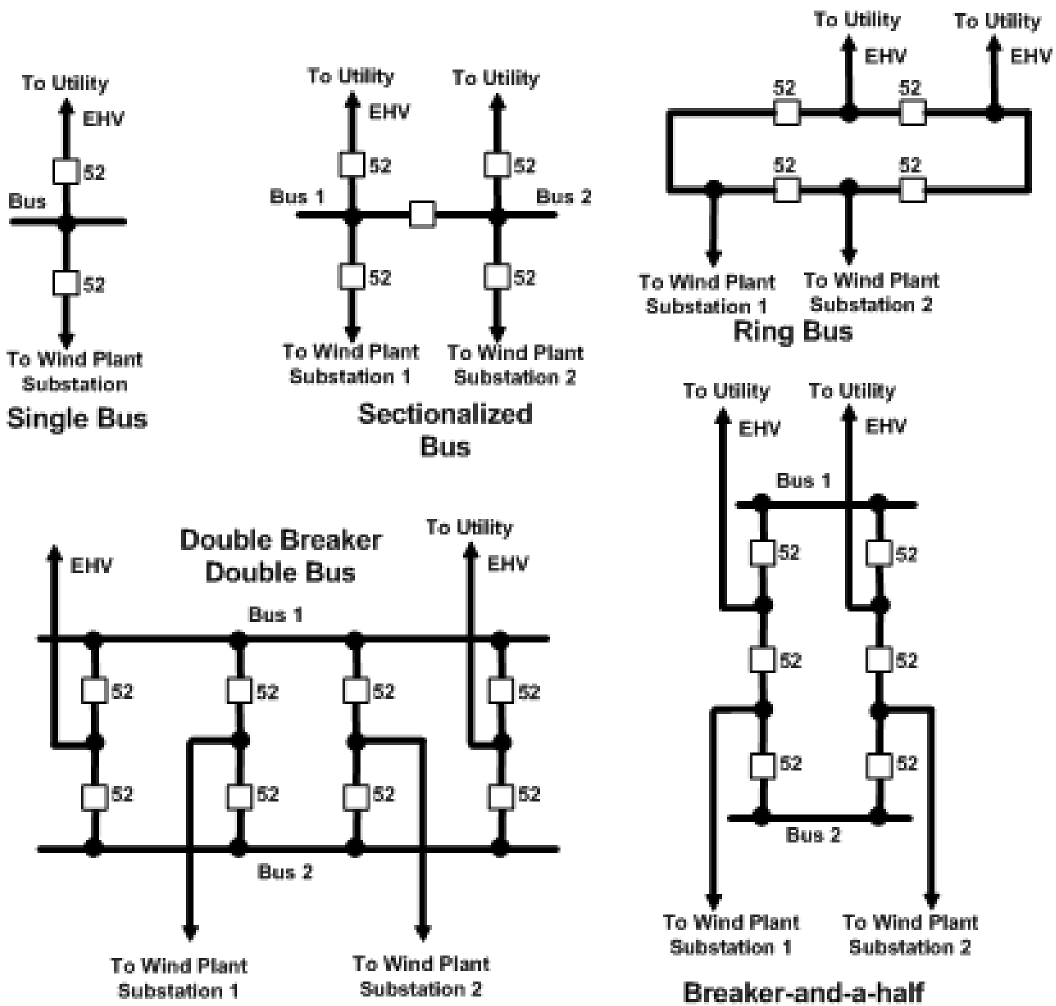

Figure 2-1: Various Switchyard Configurations.

Often significant work is necessary to coordinate modern and legacy protection schemes such as complex three terminal, weak infeed, or power line carrier (PLC) blocking/unblocking schemes. Updating existing transmission communication systems to incorporate more modern fiber optics systems for SCADA/EMS and high speed pilot protection such as line differential schemes is often necessary. Often it is required to redesign existing impedance relaying as well as directional ground protection schemes, e.g. add a pilot scheme such as permissive overreaching transfer trip (POTT) or directional comparison blocking (DCB).

Breaker failure schemes and automatic reclosing must be addressed for the interconnecting substation and switchyards. Since breaker failure and reclosing schemes may depend on voltage and supervisory over-current elements, it is typically necessary to understand the current contributions and characteristics of wind turbine generators. While C37.119™-2005 - IEEE Guide for Breaker Failure Protection of Power Circuit Breakers and IEEE C37.104™-2012 IEEE Guide for Automatic Reclosing of Circuit Breakers for AC Distribution and Transmission Lines provide guidance, these standards might not address specific issues for wind plants.

Typically circuit breakers need to be evaluated with respect to continuous current, breaker interrupting duty, and BIL ratings. It is often necessary to study the effects of transient recovery voltage (TRV) on all breakers to determine the need for grading capacitors.

The high and medium voltage buses must also be designed to withstand the momentary mechanical forces imposed by system faults. These forces are a function of the available fault duty and physical bus arrangements. Often, the fault duty available from the transmission system, especially at the HV bus, is significantly higher than that provided by the wind farm. The combined fault duty from all sources, with some margin for future system additions, must be considered in the bus design.

Once the interconnection specifications have been developed, the substation is designed based on site, availability of major equipment such as main transformers, protection schemes, and communications. The substation transformers may be specified in a variety of winding configurations such as delta/wye, wye/delta/wye, and wye/delta as shown in Figure 2-2. Specifications of electric power transformers are addressed in IEEE 57.12.00™ - 2010 - IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers. A configuration that involves a delta on the collector side requires that some other means be utilized to provide grounding of the collector bus, such as a bus-connected grounding transformer as shown in Figure 2-2(c). To provide effective grounding requires a large grounding transformer. Therefore, impedance grounding is often utilized. The degree of grounding must be considered in the station and collection system insulation coordination. Each of these configurations is used in North America, but only configuration (c) is used in Germany. IEEE 666 has the various transformer configurations for generating stations and the appropriate grounding methodologies to apply. IEEE C37.91™ - 2008 - IEEE Guide for Protecting Power Transformers contains the appropriate protection schemes that are applied to power transformers. IEEE C57.131™ - 2012 - IEEE Standard Requirements for Tap Changers has standard requirements for load tap changers. While these standards provide significant guidance, they do not specifically address WPPs.

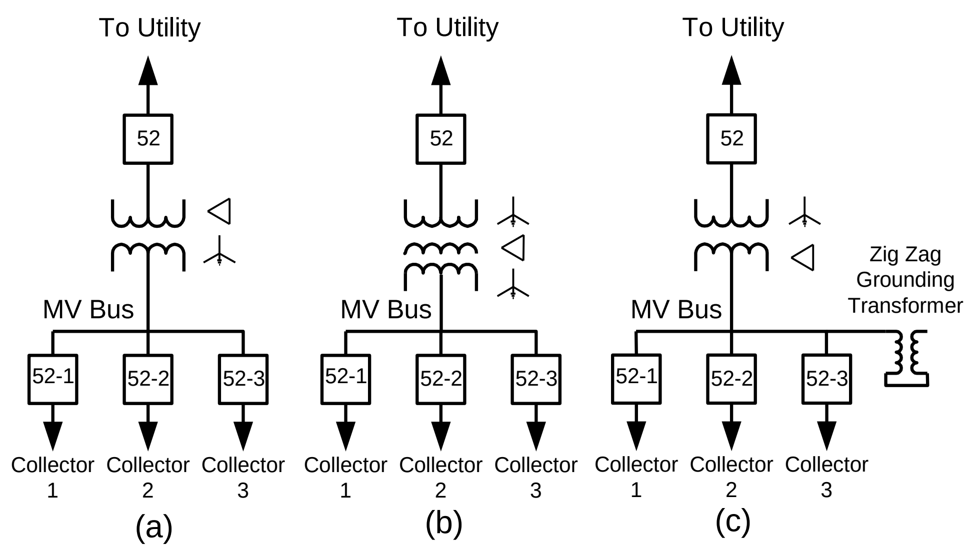

Figure 2-2: Single medium voltage (MV) bus substation configurations.

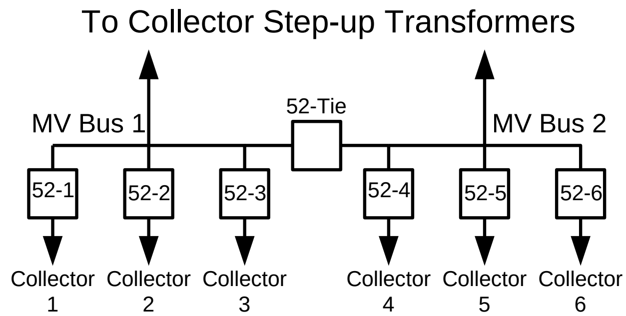

Figure 2-3: Sectionalized collector bus substation configuration.

In some countries, designers of WPPs consider the practice of under-sizing transformers as a means to reduce cost. Conceptually, this practice is based on the principle that the required transformer rating is an averaging of the allowable energy over a given period. The long thermal time constants of a transformer tend to smooth temperature variations caused by short-duration overloads. Excess hot spot temperature leads to accelerated loss of life, and it is widely believed, but not completely substantiated, that operation for short periods at elevated temperatures can produce a tolerable loss of life when balanced against periods where hot spot temperatures are less than the design value and loss of life is retarded. IEEE C57.91™– 2011 – Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators addresses issues related to insulation life of the transformer, noting that the actual relationship between the insulation life and transformer life is in question and still has not been resolved. IEEE C57.91 also emphasizes that transformer overload capability and aging is generally a function of the actual winding hot spot and top oil temperatures and provides calculation methods to estimate overload capability and aging.

The substation configuration must consider grounding, safety, reliability, and protection requirements of the utility and the wind plant collector systems. IEEE 80™ - 2000 - IEEE Guide for Safety in AC Substation Grounding discusses principal grounding considerations for the substation and discusses aspects of the soil resistivity. This standard is also relevant to the grounding method used at the WTG, which is similar to the one used in the main substation. Methods for measuring ground resistivity are provided in IEEE 81™ - 2012 - IEEE Approved Draft Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Grounding System, which are extremely important when considering trenched underground cable networks.

Often more reactive power is needed than can be supplied by the WTGs alone. Usually the cheapest solution is to install static capacitor banks at the substation level. Capacitor banks, static var compensators (SVCs) and dynamic var compensators, provide the needed var compensation for voltage support for the WTG during fault conditions. This voltage support is especially needed for a period long enough to accommodate fault clearing on the transmission system during conditions that include near-zero voltage at the high side of the wind plant interconnection transformer. This ability of WPP to remain connected to the electric system during low voltage conditions long enough to allow fault clearing is referred to as low voltage ride through (LVRT). Note that the static capacitors provide little help during low voltage prior to fault clearing, but especially help system voltage recovery after fault clearing.

State of the art approaches for mitigating harmonic issues include the use of series inductors and capacitors for single frequency tuning, C filters, or redesign of the collector system to avoid resonance issues. Protection for these shunt capacitor filter banks is discussed in IEEE C37.99™ - 2012 - IEEE Draft Guide for the Protection of Shunt Capacitor Banks. IEEE Standard 18™ - 2002 - IEEE Standard for Shunt Power Capacitors should also be referenced for individual capacitor can ratings and specifications. There is a need to identify background voltage and current distortion on the existing electric power system, which can cause issues with plant design due to harmonic resonance.

Surge arresters play an important role in the design of any WPP. Arresters are typically installed in the switchyards and substations for protection of major equipment such as transformers, capacitor banks, and SVCs. Other arresters are typically installed in the medium voltage network for protection of substation equipment as well as the medium voltage collector system. It is common practice to apply elbow-type metal oxide surge arresters at the step up transformer at the end of each collector feeder of the wind plant for underground cable collection systems. The junction points at wind turbine step up transformers and multi-cable junction points are convenient locations for connecting these elbow arresters. Several methods have been used to assess proper ratings and temporary overvoltage (TOV) withstands for these underground cable surge arresters. Due to the dynamic nature of the wind turbines during unbalanced fault conditions, TOV is common for single-line to ground faults immediately following substation collector breaker opening. Often collector cable grounding transformers are needed in order to reduce TOV to an acceptable limit within the rating of the elbow surge arrestors. Guidance can be found on these arresters in IEEE C62.11™ - 2012 Standard for Metal-Oxide Surge Arresters for AC Power Circuits (>1 kV) and IEEE C62.22™– 2009 Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems, but may not address all the specific needs for WPPs.

Although transfer trip may seem to be the ideal option for avoiding TOV across wind plant collector systems, it has not usually been implemented due to the cost of protection communication infrastructure. Another method to avoid TOV is to use the existing circuit breaker and add a three phase grounding switch to the collector system. The switch is closed via the circuit breaker auxiliary position contacts. This method is more complicated but is necessary due to the lack of dynamic models for analyzing fault contributions on collector systems. This system is not widely used due to the TOV conditions between the time of the circuit breaker tripping and the three phase grounding switch closing. Newer methods have been developed, as shown in Figure 2-4, using medium voltage circuit breakers incorporating an internal, mechanically interlocked three phase ground switch that can close in approximately 14 milliseconds. This method must include current inputs from the ground switch to subtract the switch current from the substation bus differential protection to avoid false tripping when the circuit breaker is open. Alternatively without the ground switch CTs, the bus differential relay might be connected to the bus-side CTs and collector relay connected to the collector-side CTs. This arrangement would leave the breaker outside of the differential protection zone, so that some other breaker failure protection method may be required.

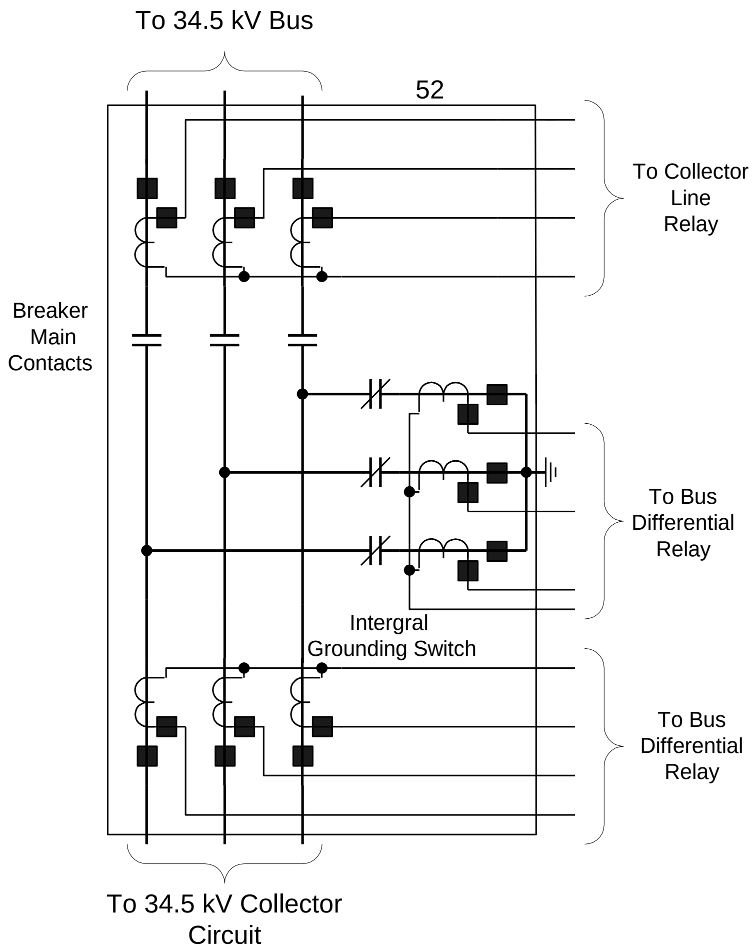

Figure 2-4: Medium voltage circuit breaker with internal mechanical interlocked three-phase ground switch

Once interconnection agreements identify the substation layout (see Figure 2-1 for examples), turbine selection and electrical collection system planning, optimization, and design can proceed. These electrical collector systems are normally operated at the highest medium voltage, 34.5 kV in North America or 33 kV in Europe, but are sometimes designed to operate as low as 12 kV depending on the substation voltages available. The 12 kV cases typically rely on existing infrastructure that may be too costly to change or reconfigure. Sometimes existing infrastructure, economics, and availability of equipment such as 12 kV cable systems and generator step-up transformers will drive the decision to operate at a lower voltage. When separate grounding transformers are used, as in Figure 2-2(c), they are connected to the medium voltage bus rather than the transformer so that the system will still have a ground reference following transformer faults and isolation.

The substation is often located in a centralized location with respect to the WPP, thereby reducing cost of the collector lines and increasing efficiency. Factors which may tend to offset the choice of a centralized location include soil and terrain conditions, excavation requirements for the substation and transmission lines, access for personnel and equipment, or other economic or technical considerations.

2.2. Collector System

The collector system design considers grounding and efficiency. These aspects help determine the application of either overhead or underground systems, the interconnection of the collector system to the substation/switchyards and transmission lines which are coupled to the grid. Considerations during the system design phase includes: equipment ratings especially breaker ratings; transformer protection especially during through faults; protection of collector cables, conductors and generator step up transformers; and the effect of associated grounding on protection and equipment ratings. Important factors in deciding between overhead or underground lines include the thermal resistivity of the soil and the cost of the system as well as local land owner requirements and number of crane crossings during the initial construction phase. Each collector line on of the substation may have a unique configuration, Figure 2-5 is an example of a line configuration.

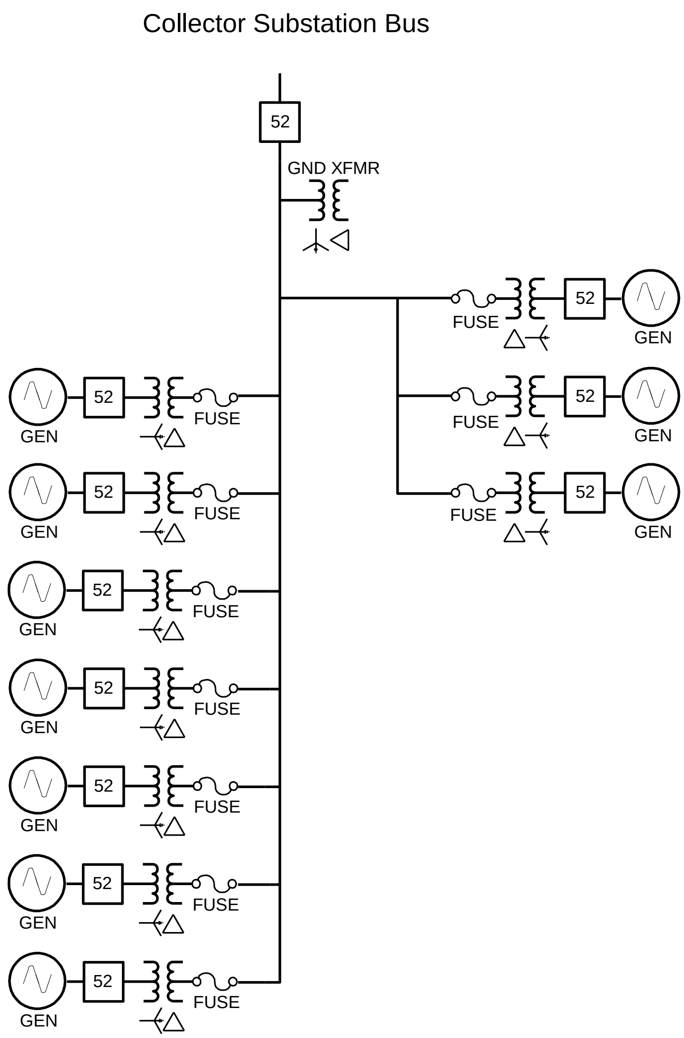

Figure 2-5: Collector system configuration example.

WPPs are often designed with multiple collectors, but can be designed with a single collector. This is solely dependent on the number of turbines and the cable size. Each collector is a series of above ground line or underground cables that deliver power from the wind turbines to the collector substation and point of interconnection (POI).

The collector system design is usually based on a combination of logistics, environment, soil requirements, grounding, economics, protection, operation, maintenance, and efficiency. Collector systems may be a combination of overhead transmission lines for interconnecting the wind plant substation, and overhead lines, trenched underground or submarine cable systems for the collector system. The collector cable or conductors are evaluated to minimize losses, voltage drop and satisfy dependability, security, and maintenance criteria. Underground cables often have hard drawn neutrals with concentric neutral cabling and counterpoise grounding systems.

Depending on the type of turbine, the interconnection of the collector system to the turbine could be direct or through a pad-mounted transformer on the WTG ground floor. Wind turbines that are directly connected to the collector system typically have a transformer within the nacelle, which houses the major WTG equipment at the top of the tower. Most often the connection is through a transformer that raises the generator voltage (typically 690 V or lower for generators smaller than 3 MW and 3.3 or 6 kV for larger generators) to the collector system voltage (up to 34.5 kV). The specific design depends on design voltage of the turbine-generator manufacturer.

The individual feeder collector lines can have issues during unbalanced faults. Grounding transformers or other grounding mechanisms for effectively grounding the system neutral may be required when the substation collector breaker is open, or when schemes are implemented at the wind turbine generator per the requirements of FERC Order No. 661 – Interconnection of Wind Energy. Due to the complexities and dynamic behavior of WPPs, detailed line constants parameters for undergrounded cables such as XLPE are needed for transient analysis.

Industrial and commercial power systems standards are sometimes used for sizing collector cables and determining grounding requirements as well as for specifying protective equipment and device coordination. These standards include at least IEEE 242™ - 2001 - IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems (IEEE Buff Book), IEEE C37.95™ - 2002 - IEEE Guide for Protective Relaying of Utility-Consumer Interconnections, NEC, and NESC codes. However, cable ampacities should be determined based on actual soil thermal resistivity and installation conditions because conditions at actual wind plant locations are often substantially more severe than assumed in standard cable ampacity tables. Cable size may also be based on a total life cycle basis, considering the economic value of losses. In this case, ampacity is often not a limiting factor.

Various methods may be applied for coordination of protective device settings (i.e. relays and fuses), which should consider the full impact of wind turbine generator fault contributions on these medium voltage collection systems. One method to protect underground cable systems uses definite time overcurrent which provides time-delayed coverage to the first protective device on a collector circuit, and inverse time-overcurrent to detect faults out to the farthest remote end of the collector circuit. Since wind collector circuits may have 15 or more wind turbines per feeder and can extend over 10 km, it is often difficult to set the minimum pick-up of a non-directional time over current element to reach the farthest protective device on this circuit without limiting maximum load and preventing inadvertent trips for transformer inrush on circuit energization. Coordination often requires directional supervision of overcurrent elements. Composite time overcurrent elements may be used which overlap to provide appropriate reach to the farthest remote protective device as well as avoid overreaching the first protective device of the circuit. Protection of collector systems serving Type IV WTGs with overcurrent functions can be problematic since these machines are designed to limit their current to only slightly above the nominal rating. Off shore installations in the North Sea have used differential protection.

2.3. Interconnection and Collector System Studies

Studies are performed in phases as more details are established with the acquisition of permits, equipment, logistics, and economics associated with the particular project. These processes aid in the selection of the type of wind turbines, siting, and availability. The objective is to identify and study all the important effects of the wind power plant system on the power system.

The proposed site layout and turbine placement, including the substations and switchyards are considered. Load flow planning studies aim to maximize power transfer to the grid with an optimal voltage profile. Available fault duty contributions from the grid as well as from the wind plant are examined.

Transient recovery voltage and breaker ratings considering grading capacitance are typically examined, as well as transient switching phenomenon which will verify insulation, insulator, and BIL ratings for equipment and arrester systems.

Power quality issues, particularly harmonic resonance, can be present as a result of the large inductive and capacitive networks in a wind plant. IEEE Standard 519™-1992 – Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems recommends general practices and requirements for the control of harmonics but does not recognize the impact of harmonic interaction from a utility onto a wind plant or vice versa. Where grid codes apply, maximum harmonic levels will be specified by those codes. Power quality studies may include static reactive compensation such as capacitor banks at substations and on individual wind turbines. Assessment of the background voltage and current distortions in combination with wind turbine contributions and reactive compensation equipment tuning helps determine the power quality. Frequency scans are performed to identify any unacceptable resonance conditions and aid in avoiding or mitigating those conditions.

System studies include TOV conditions and over excitation of transformers. Effective grounding equipment is considered to address system conditions, especially those which have a significant effect on the zero sequence, such as unbalance faults, open phases and delta connected transformers.

Fault ride through impact studies are performed for high and low voltage ride through conditions.

Protective device coordination and specification is performed for all protective devices between the individual wind turbines and the transmission grid.

3. Wind Turbine Generator Response to Faults

Wind Turbine Generators may be classified in five types. Type I is a squirrel cage induction generator. Type II is a wound rotor induction generator with an adjustable resistor in the rotor circuit. Type III is a variable speed asynchronous wound rotor generator which has a three phase AC field applied to the rotor from an AC to DC to ac converter, the power source for which is the generated voltage. Type IV is an AC generator in which the stator windings are connected to the power system through AC to DC to AC converter. Type V generators use a variable speed / variable ratio hydraulic fluid coupling transmission to use the variable speed input from the turbine blades to drive a traditional synchronous generator at fixed synchronous frequency.

Both Type I and II generators are commonly configured with shunt capacitors which are switched on the generator terminals, as shown in Figure 3-1 and Figure 3-2. These capacitors make it possible for these generator units to produce both real and reactive power. Both Type III and IV generators are able to produce real power and reactive power by adjusting the inverter controls, as shown in Figure 3-3 and Figure 3-4. Type V generators have similar voltage control capability as other synchronous generators and may be coupled through a hydraulic or continuously variable transmission, as shown in Figure 3-6.

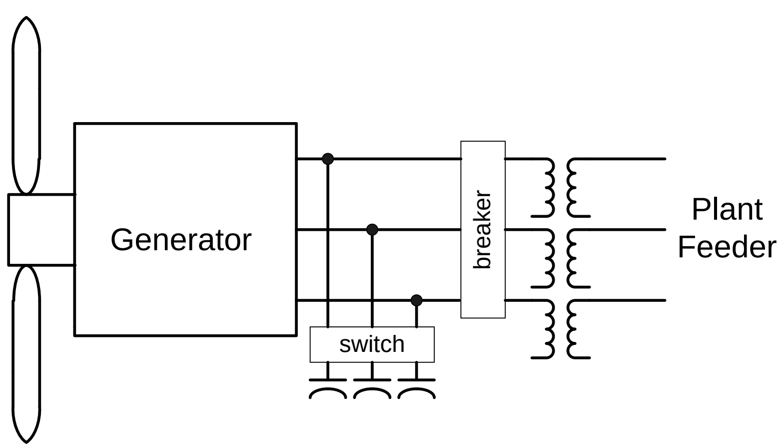

Figure 3-1: Basic configuration of a Type I single cage wind turbine generator.

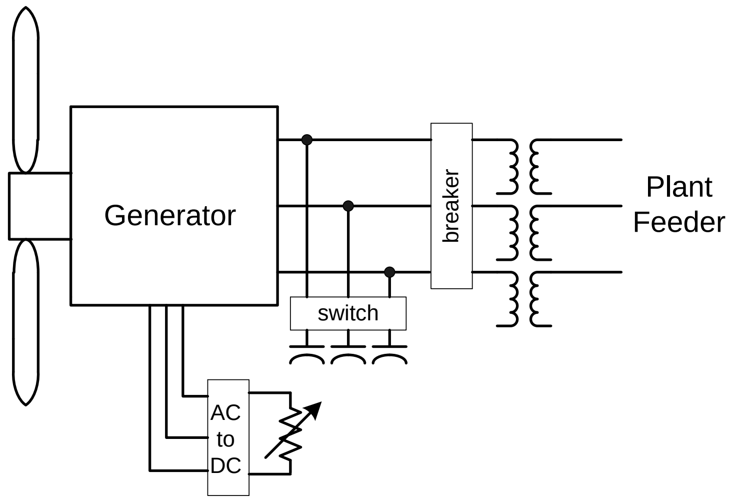

Figure 3-2: Basic configuration of a Type II single cage wind turbine generator.

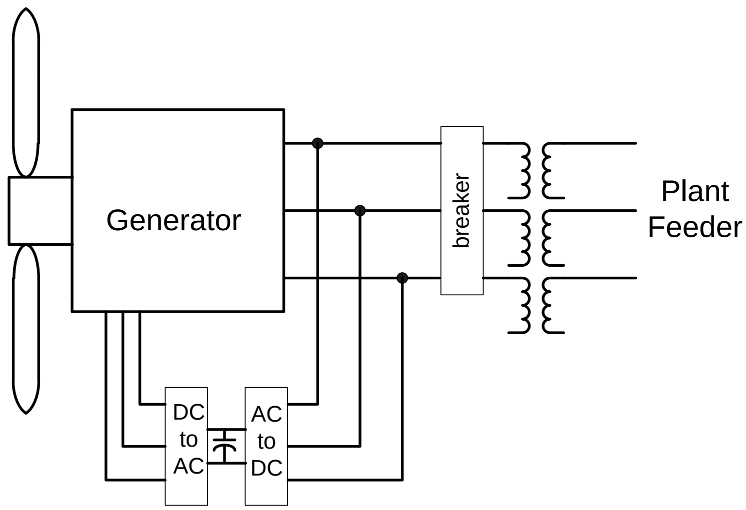

Figure 3-3: Basic configuration of a Type III double fed wind turbine generator.

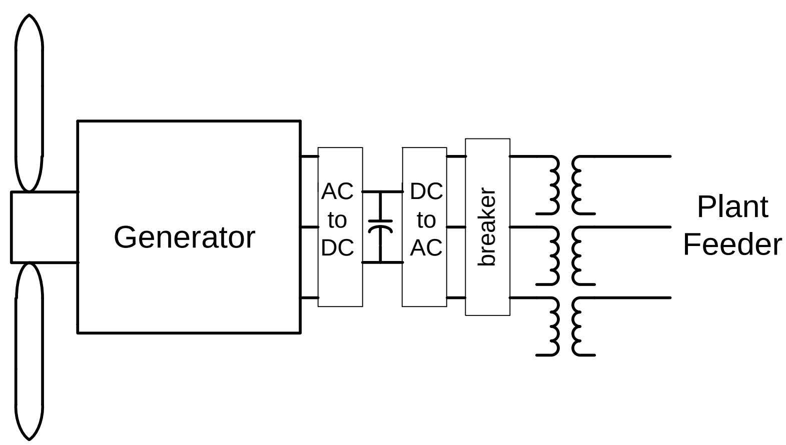

Figure 3-4: Basic configuration of a Type IV full power converter wind turbine generator.

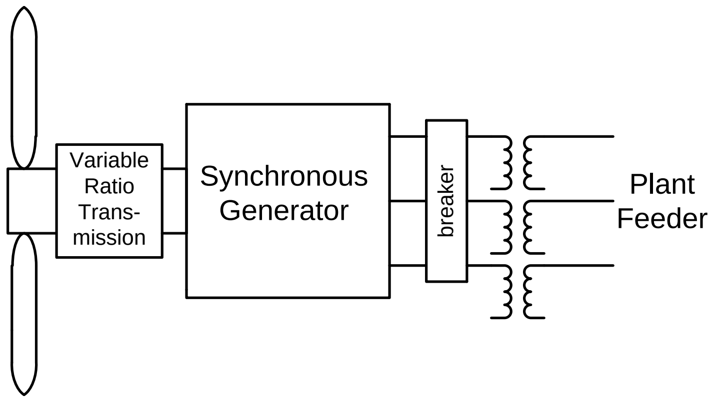

Figure 3-5: Basic configuration of a Type V wind turbine generator.

3.1. Type I

3.1.1. Squirrel Cage Induction Machine Wind Turbine Generators

A one-line diagram of a typical Type I WTG is shown in Figure 3-6. The Type I WTG uses a squirrel cage induction machine (SCIM). The induction machine is connected to the wind plant collector system through a step-up transformer and a soft starter. Power factor correction capacitors (PFCC) are typically included at the base of the turbine tower. Several steps of PFCC are used for different operating speeds of the turbine shaft. The turbine shaft speed is controlled to a nearly constant value.

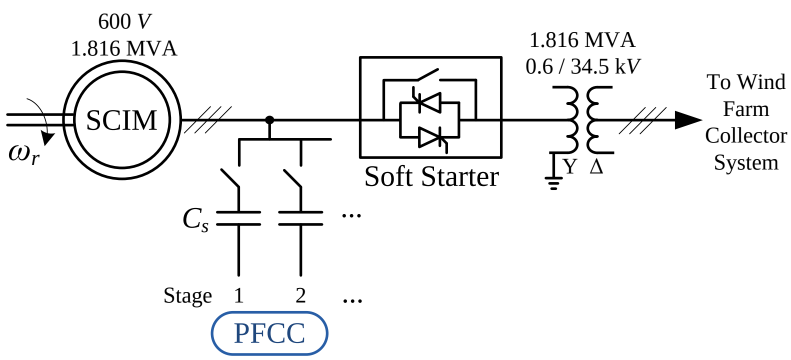

Figure 3-6: Typical connection of a Type I wind turbine generator to the wind plant collector system.

The short circuit behavior of the squirrel cage induction machine is described in this section. The effects of the step-up transformer and power factor correction capacitors are described in the next section.

The system was simulated as shown in Figure 3-7 with the machine connected to an ideal voltage source through an impedance, e.g. 0.01 + j0.05 per unit. The parameters of the machine are given in Table 3-1 and the base quantities used for per-unitization are given in Table 3-2. The machine winding neutral point is floating. It is assumed that the machine is delivering rated power at the time of the fault and the machine rotor speed does not change during the fault. Simulation results shown here were obtained using

PSCAD®/EMTDC, but it is shown in [1] that PSCAD®, EMTP/RV, and SimPowerSystems software packages give similar results for a similar network.

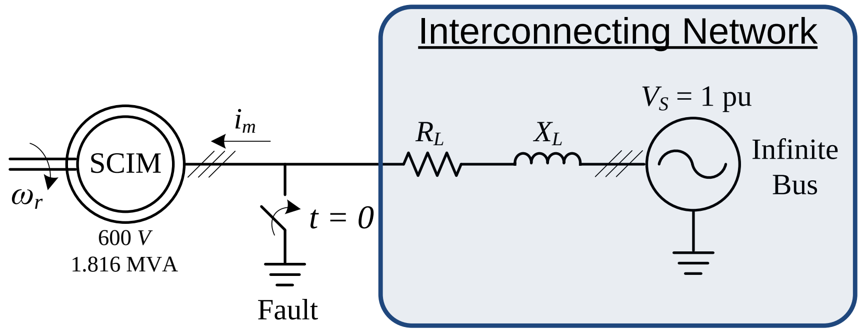

Figure 3-7: Network used for simulation of a squirrel cage induction machine under short circuit at the machine terminals.

Table 3-1: Type I Induction Machine Parameters

Stator Resistance	R_s	0.0008	Ω	0.0040	pu
Stator Leakage Reactance	X_s	0.0173	Ω	0.0873	pu
Stator Leakage Inductance	L_2	4.589e-5	H	0.0873	pu
Magnetizing Reactance	X_m	0.7783	Ω	3.9261	pu
Magnetizing Inductance	L_m	0.002065	H	3.9261	pu
Rotor Resistance	R_2	0.002	Ω	0.0101	pu
Rotor Leakage Reactance	X_2	0.0143	Ω	0.0721	pu
Rotor Leakage Inductance	L_2	3.794e-5	H	0.0721	pu
Inertia	J	560.05	kg*m²	4.87	sec
Poles	-	6	-	-	-

Table 3-2: Base Quantities For Per-Unitization.

Quantity	Symbol	Base Value (Eq.)	Base Value (Num.)	Unit
Power	Pb	1,816,000/3	605,333	VA
Voltage	Vb	600/√3	346.41	V
Impedance	Zb	Vb2/Pb	0.1982	Ω
Current	Ib	Vb/Zb	1,747.4	A

The equivalent circuit of an induction machine is shown in Figure 3-8 with conventional notations. The rotor resistance R_2 represents the actual rotor resistance R_r referred to the stator for Type I machine.

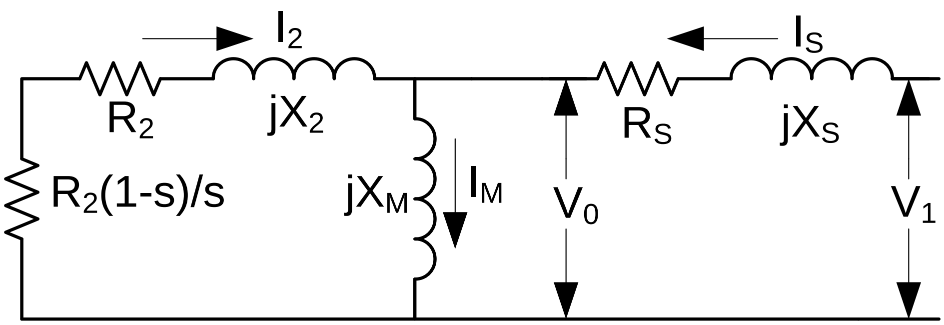

Figure 3-8: Equivalent circuit of an induction machine.

Simulation results for the network in Figure 3-7 are shown in Figure 3-9 for a three phase to ground fault and Figure 3-10 for a phase A to ground fault. Prior to t = 0, the machine is in steady state. When the three phase fault is applied at t = 0 (Figure 3-9), the machine terminal voltages drop to zero and the machine currents increase substantially, then eventually decay to zero due to the loss of an external excitation source. Phase A current reaches nearly 14 per unit in peak of the first cycle due to the large DC offset in the current. The DC offset changes in each phase over a cycle of the fundamental frequency depending on the instant at which the fault occurs.

The simulation results in Figure 3-10 indicate that the magnitude of the short circuit currents are lower for a phase A to ground fault than the three phase to ground fault, with the first peak of the phase A current reaching nearly 10 pu. Phase B and C remain connected to the network and maintain flux in the machine windings, so the currents do not decay to zero.

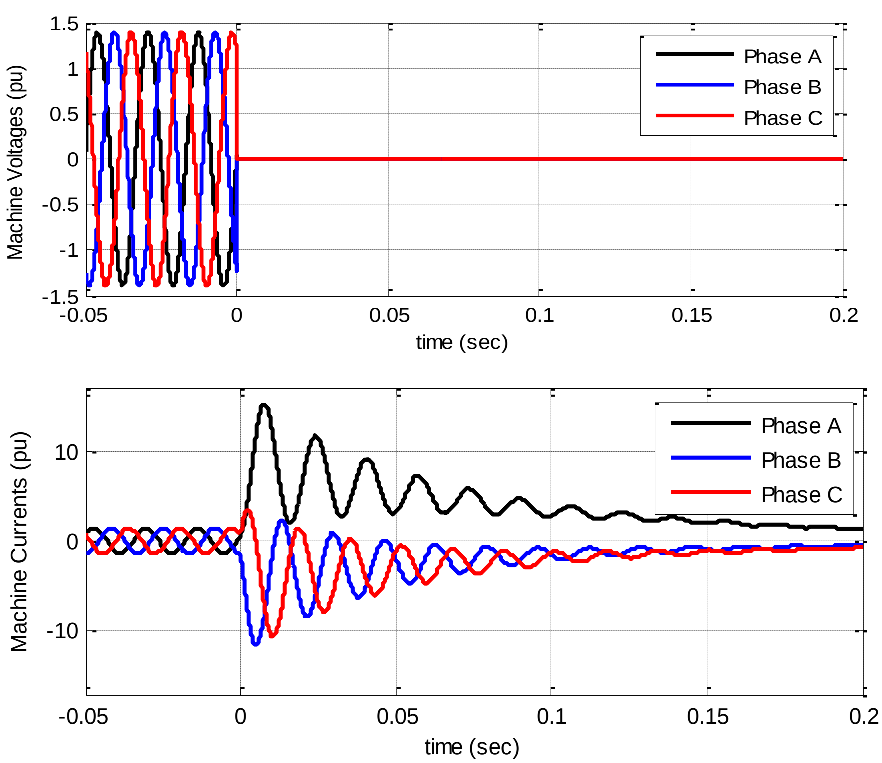

Figure 3-9: Machine terminal voltage and current for a three phase fault.

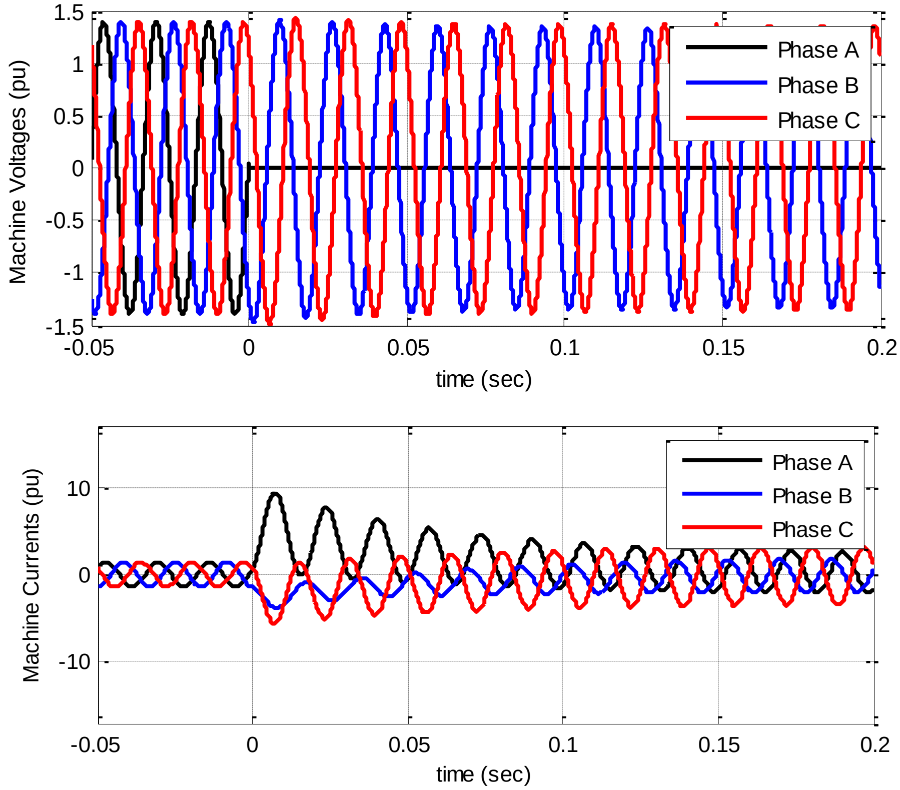

Figure 3-10: Machine terminal voltage and current for an A phase to ground fault

Since the network remains symmetrical during a three phase short circuit, no negative or zero sequence current flows in the network of Figure 3-7. The initial short circuit current can be calculated using the positive sequence network shown in Figure 3-11. The voltage behind transient reactance V' can be calculated using a simplified representation [2], [3]

$$V' = V_s - (R_s + R_L)I_s - j(X' + X_L)I_s \tag{3.1}$$

where I_s is the stator current going into the machine prior to the fault and X' is the transient reactance, calculated by

$$X' = X_s + \frac{X_m X_2}{X_m + X_2} \tag{3.2}$$

Thus, the initial RMS short circuit current in the machine after the fault occurs is calculated from the circuit in Figure 3-11 after the switch closes at t = 0 is given by

$$I_{SC} = \frac{V'}{R_s + jX'} \tag{3.3}$$

A good approximation to the decay of the AC component of the machine stator current after the short circuit is determined by the rotor transient time constant, given by

$$T_r = L_r'/R_2 \tag{3.4}$$

where Lr' is calculated by

$$L_r' = L_2 + \frac{L_m L_s}{L_m + L_s} \tag{3.5}$$

Thus the magnitude of the RMS current after a three phase short circuit is calculated by

$$|I(t)| = |I_{sc}|\, e^{-t/T_r} \tag{3.6}$$

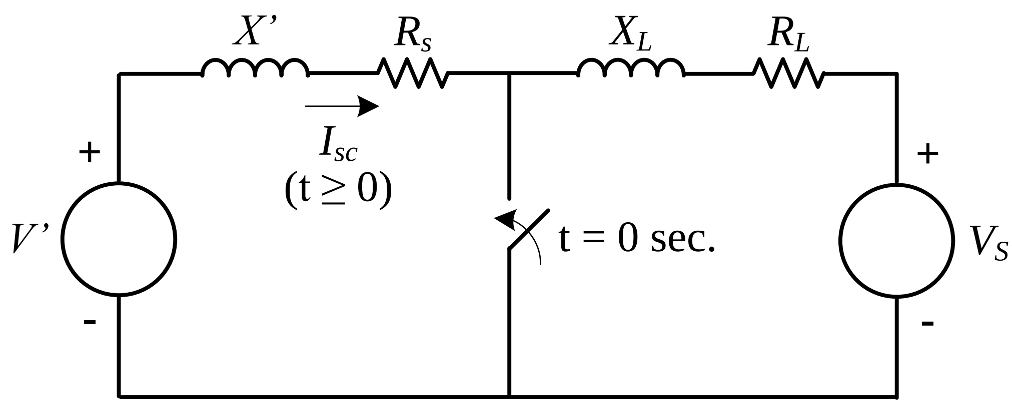

Figure 3-11: Sequence network circuit for three phase fault.

For the phase A to ground fault, positive, negative, and zero sequence currents flow in the network of Figure 3-7. Therefore, the sequence network circuits of Figure 3-12 are used for the phase A to ground fault case. No zero sequence current flows in the machine since the stator winding neutral is floating. The network of Figure 3-12(a) is used to calculate the initial RMS short circuit current I_{sc}, and the network of Figure 3-12(b) is used to calculate steady state currents I_{ss} flowing in the network after the transients in the unbalanced network have died away. Similar calculations shown above for the three phase short circuit can be performed for the phase A to ground fault case, except the steady state component of the short circuit current must be incorporated and calculated by

$$|I(t)| = |(I_{sc} - I_{ss})|\, e^{-t/T_r} + I_{ss}| \tag{3.7}$$

Where I_{sc} and I_{ss} are the phase currents found from solving for the sequence currents in Figure 3-12 and converted using the symmetrical components transformation [4].

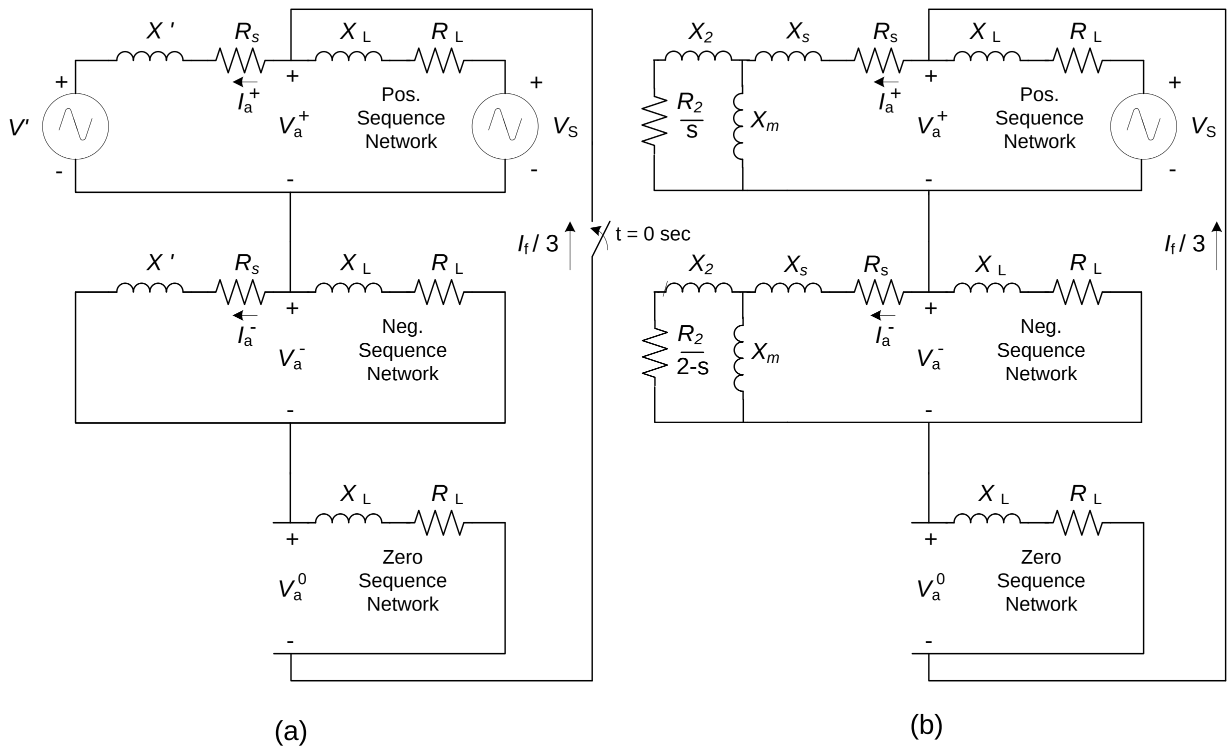

Figure 3-12: (a) Transient and (b) steady state sequence network for single line to ground fault.

Calculation of the RMS short circuit currents in this way were compared to extracted RMS currents from the PSCAD® simulations results in [4], and shown to match closely for a three phase short circuit (less than 1% error, both curves plotted but so similar they are not readily distinguishable) but resulted in some error for a phase A to ground fault (~14% error in phase B calculation). A comparison of the calculation in equation (3.6) and simulation results for a three phase short circuit are shown in Figure 3-13(a). A similar comparison is shown in Figure 3-13(b) for a phase A to ground fault using equation (3.7). The error in the initial short circuit current calculation using this method can be seen in Figure 3-13(b) since there is a small deviation from the calculated current at t = 0 and the simulated current.

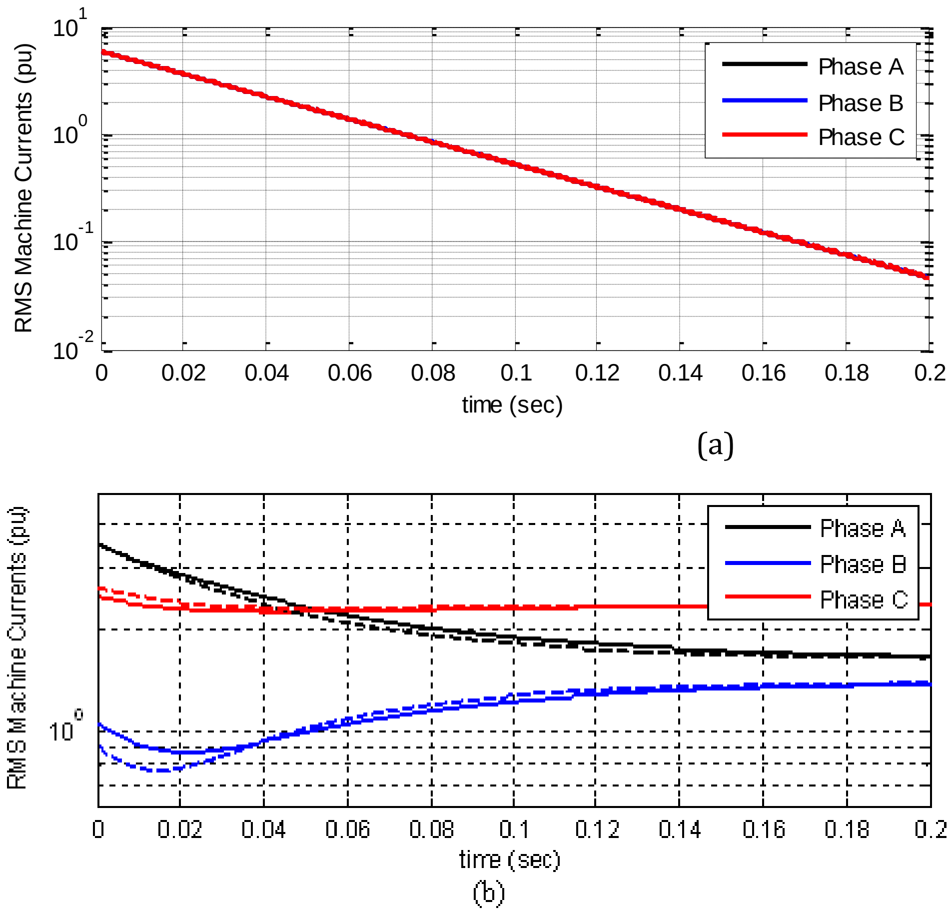

Figure 3-13: RMS machine current magnitude over time for a (a) three phase short circuit, top figure, and (b) phase A to ground short circuit occurrence, bottom figure, at t = 0 (solid = simulated, dashed = calculated).

3.1.2. Effects of PFCC and Step-Up Transformer

The cable and WTG step-up transformers were added to the simulation in Figure 3-14**Figure 3-14** and the same faults applied to the collector system cables. The transformer parameters are given in Table 3-3 and the magnetizing branch and saturation has been neglected. The medium voltage winding of the transformer is connected to an ideal voltage source through an impedance of 0.001 + j 0.001 per unit. The PFCC is set to give the generator unity power factor at rated power output.

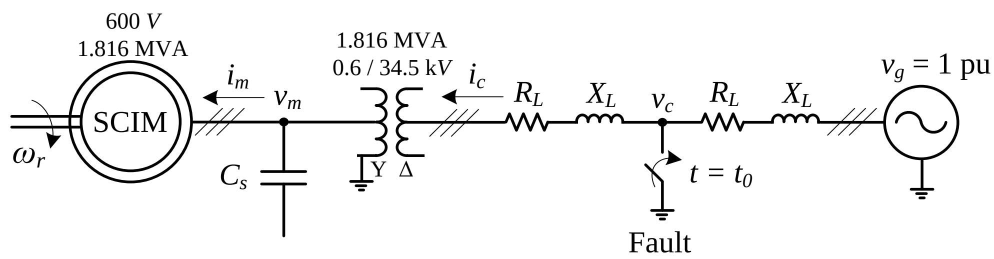

Figure 3-14: Network used for simulation of a Type I wind turbine generator with power factor correction capacitor and unit step-up transformer.

Table 3-3: Generator Step-up Transformer Parameters.

Rated Power	1.816	MVA
Primary Winding Rated Voltage	600	V
Secondary Winding Rated Voltage	34.5	kV
Positive Sequence Leakage Reactance	0.0563	pu
Copper Losses	0.006	pu
Core Losses	0	pu
Magnetizing Reactance	∞	pu

Typical responses of the Type I WTG for a three phase to ground and single line to ground fault on the collector system are shown in Figure 3-15 and Figure 3-16, respectively. A high frequency component can be seen in many of these currents and voltages due to the resonance caused by the PFCC. The resonant frequency is much higher than the fundamental, and decays quite rapidly.

Figure 3-15 shows that the machine short circuit currents are not as high as in the case of a fault at the machine terminals, as shown in Figure 3-9(a). This is due to the increased impedance between the machine and the fault. The machine terminal voltage in Figure 3-15 does not immediately become zero after the fault on the collector system, but decays with the machine current.

Similar results are shown in Figure 3-16 for the phase A to ground fault on the collector system. The magnitude of the machine short circuit currents is less than the case of a fault at the machine terminals. The collector system voltage in Figure 3-16 shows a drop in the phase A voltage to zero, however the machine terminal voltages primarily see a drop in the phase A and B voltages. This is due to the winding connections of the unit step-up transformer. Because the medium voltage side of the step-up transformer “sees” the line-to-line voltages on the collector system, voltages V_{ab} and V_{ca} see more of a decrease than voltage V_{bc} (because the fault is on phase A), thus two of the phases on the low voltage side see the most voltage drop. Note that for faults away from the machine terminals, the time constants in which the short circuit currents decay change based on the system components in between the fault and the machine.

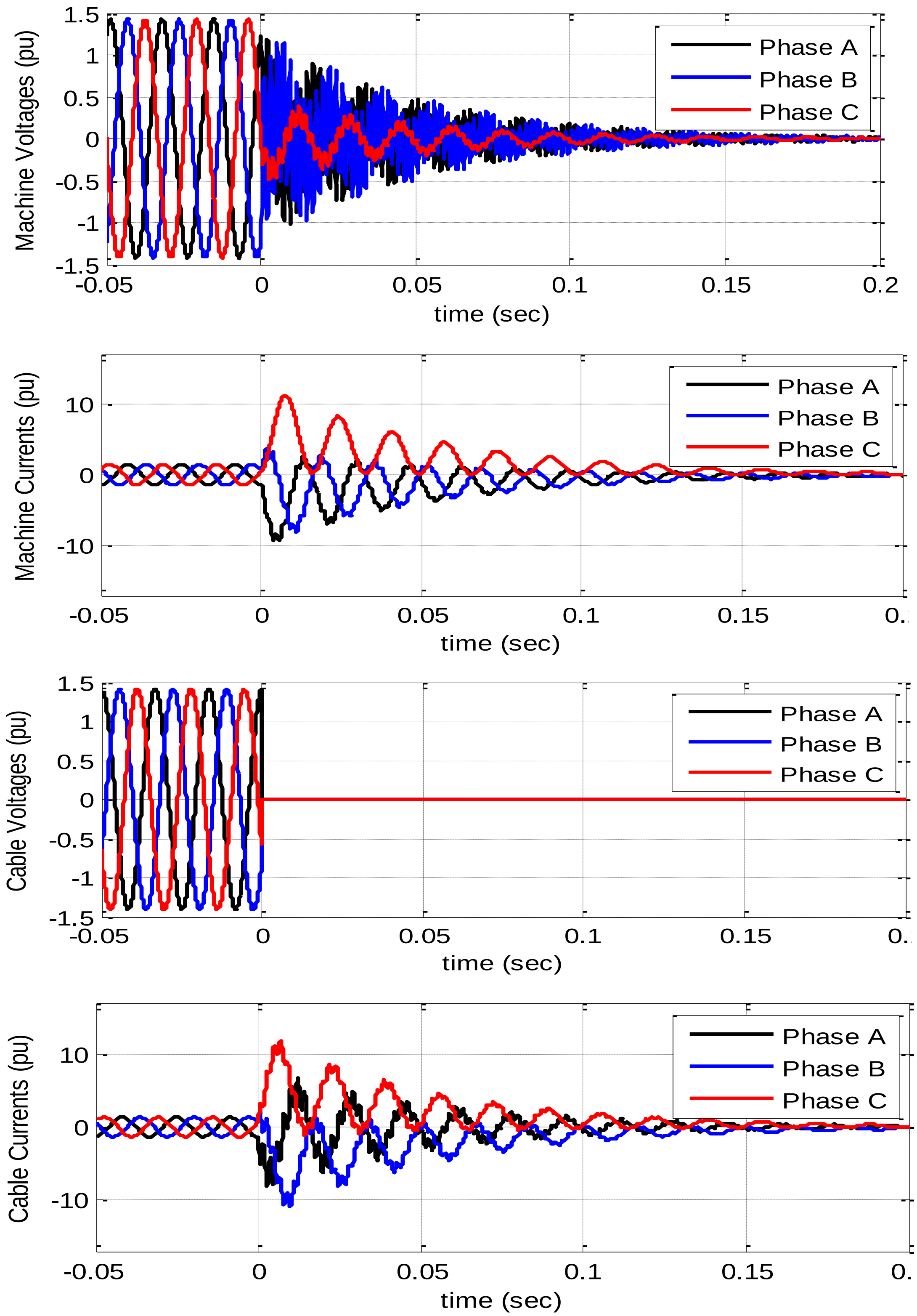

Figure 3-15: Simulation results of the network in Figure 3-12 for a three phase to ground fault on the collector system

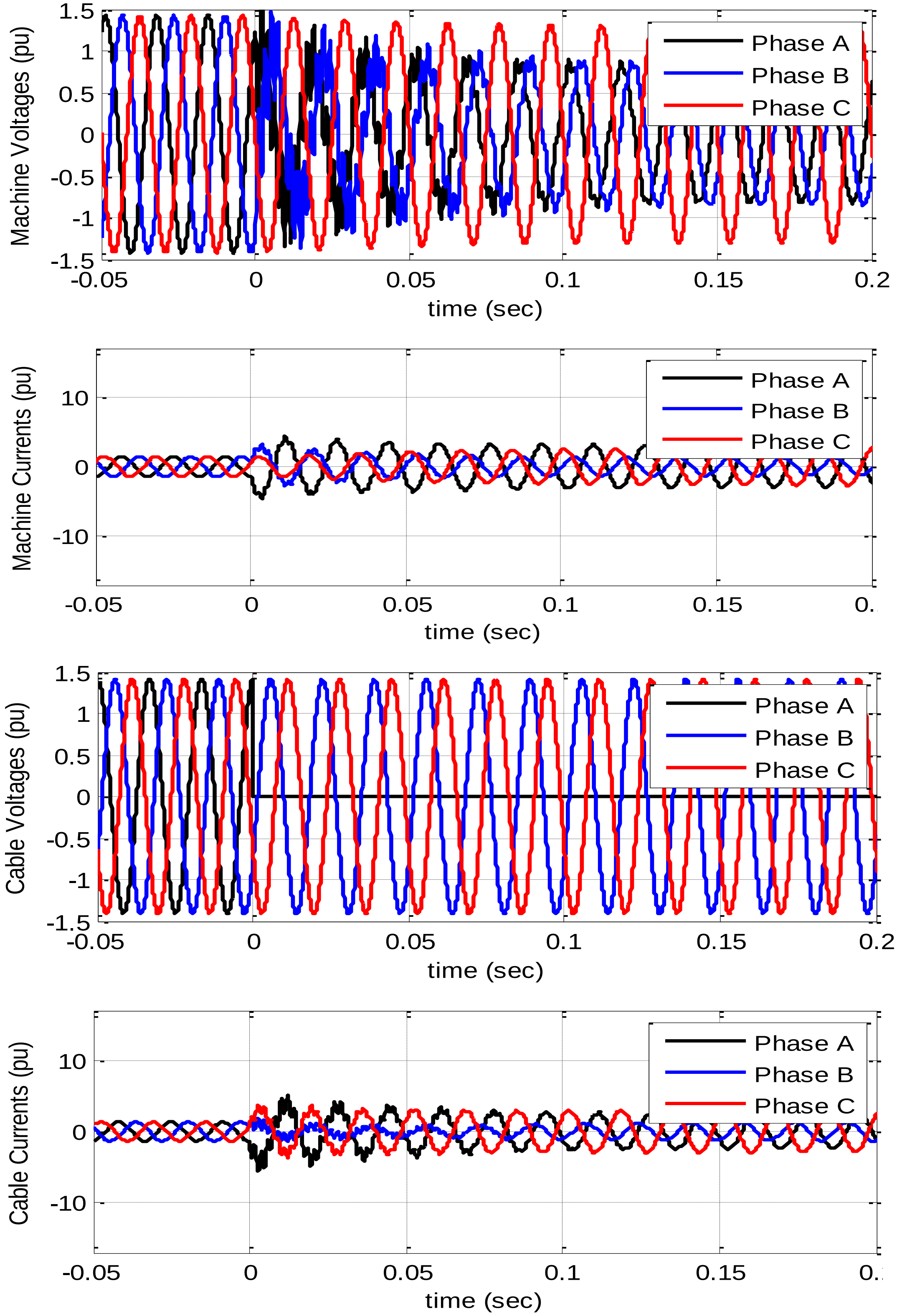

Figure 3-16: Simulation results of the network in Figure 3-12 for a phase A to ground fault on the collector system.

3.2. Type II

3.2.1. Fault Contribution from Type II Induction Generator

Type II induction machines have external resistance inserted into the rotor circuit to facilitate operation over a wider range of slips compared to a Type I induction machine. The same equivalent circuit of an induction machine, as shown in Figure 3-8, can be used for the Type II machine but the rotor resistance R_2 which represents the actual rotor resistance R_r referred to stator for Type I machine, is representing the rotor resistance R_r plus the external rotor resistance R_{ext} for Type II machine. Generally it is not critical to model the controls for this external rotor resistance. The maximum fault contribution will always occur for an external resistance value of zero.

In Section 3.1, equation (3.2) was used with conventional notations to calculate the transient reactance of a Type I machine. For Type II machines, especially at higher slips the external rotor resistance is larger. To investigate the effect of external resistance, we consider the Type I machine that was used for simulations in Section 3.1. For convenience, the pertinent ratings and parameters of this machine are reproduced in Table 3-4.

Table 3-4: Type I Induction Machine Parameters.

Machine rating 1.816 MVA, 0.6 kV	
R_s	0.0040 pu
X_s	0.0873pu
X_M	3.9261 pu
R_r	0.0101pu
X_r	0.0721 pu

This Type I machine can generate its rated power at 0.922 power factor lagging at -1% slip. To generate the same power at the same power factor at different speeds, an external resistance must be connected to the rotor circuit. Table 3-5 lists the external resistance needed to drive the machine at -2% and -3% slip. Reference [5] provides the calculation procedure.

Table 3-5: External Rotor Resistance to Operate,

Type II Induction Machine at Different Slips

Case	Slip	External rotor resistance
1	-1%	None (Type I)
2	-2%	0.009890 pu
3	-3%	0.019596 pu

External resistances required to drive the machine at -2% and -3% slips amount to 98% and 194% respectively of the internal rotor resistance of the machine. For 10% slip, it increases to 817%.

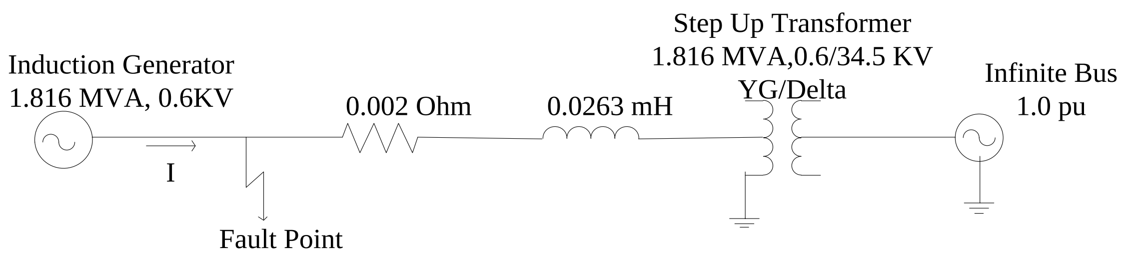

Figure 3-17: Simulation model to obtain short circuit characteristics of Type II Induction Generator.

The system shown in Figure 3-17 was simulated using PSCAD® for the three cases documented in Table 3-5. The circuit configuration is the same as used in Section 3.1. A three-phase fault was modeled at the terminals of the induction generator. Short circuit responses of the machine for the three cases are shown in Figure 3-18. Clearly, the short circuit response changes significantly at higher slip. Higher rotor resistance decreases the peaks of the AC component of the fault current, i.e., increases the damping significantly. In addition, external rotor resistance does not affect the rate of decay of the dc component. These curves indicate that it may be advantageous to include the external rotor resistance in the short circuit model..

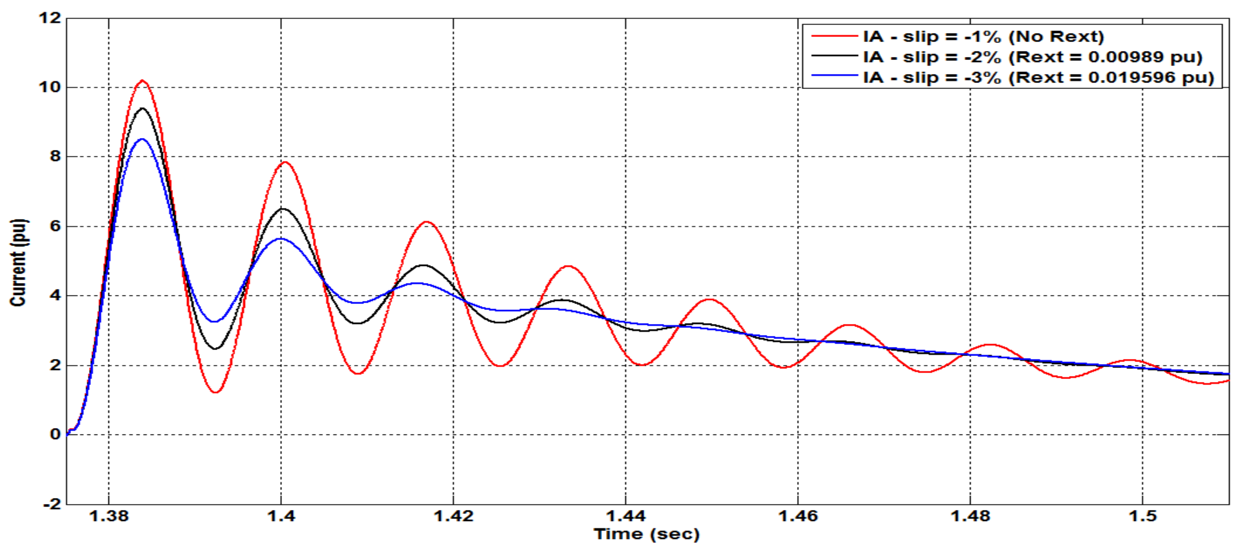

Figure 3-18: Short circuit response of the induction generator to a three-phase fault at its terminals for different slips, operating in the system shown in Figure 3-17.

For the circuit shown in Figure 3.17, fault current was calculated for fault at the generator terminals. Conventional bus impedance matrix (Z_{BUS}) based analysis was performed. The prefault voltage at the generator terminals was obtained from the PSCAD simulation. The machine impedance Z' was calculated using equations (3.8). Equation (3.8) is the expanded version of equation (3.2) to include the rotor resistances.

$$Z' = R + jX = jX_s + \frac{jX_m(R_2 + jX_2)}{jX_m + (R_2 + jX_2)} \tag{3.8}$$

The total RMS short circuit current was calculated using equation (3.9), and then the contribution from the generator was obtained.

$$I_{SC} = \frac{V'}{Z_{TH}} \tag{3.9}$$

Z_{TH}, the Thevenin impedance at the generator terminals in equation (3.9) was calculated using both equations (3.2) (X' doesn't use rotor resistance) and (3.8) to observe the effect of the external rotor resistance on the short circuit model of a Type II machine. The calculated values of the generator contribution to fault are presented in Table 3-6 which show that the difference in the results from using equation (3.8) and (3.2) increases at higher slips.

Table 3-6: Calculated Fault Current with and without External Rotor Resistance.

Slip	Calculated fault current with rotor resistance	Calculated fault current without rotor resistance	Difference in the two values
	Fault current (A)	Fault current (A)	%
-1%	10880	10882	0
-2%	10660	10548	1.05
-10%	9726	10520	8.16

These results also indicate that normal controls of the rotor resistor value will have some effect on fault current magnitude at fault inception. However, the impact is only a few percent over the range of slip modeled. Therefore modeling the resistor controls or the specific resistor value at fault inception is not critical.

3.2.2. Fault Contribution from a Type II Wind Plant

Utilities are more interested in finding fault contribution from a wind plant rather than from a single generator. Thevenin models can be used to represent Type I and Type II induction generators. However, a wind plant usually has many such generators, each connected to a step up transformer. The generator-transformer units are connected in parallel through cables forming the collector circuit. Several such collector junctions are then connected through step-up transformers to the grid. It has been proposed [6] that all the cables in the collector circuit must be taken into account to calculate the Thevenin impedance of a wind plant. However, this is not necessary for faults external to the wind plant. The equivalence of the wind plant can be made very easy by simply disregarding collector system cable impedances without introducing significant errors on the utility side of the step up transformer [7].

To illustrate this point, consider the machine parameters from the Mountain wind plant in southwestern Wyoming, available at the IEEE PSRC web site [8]. The machine parameters are listed in Table 3-7 in per unit using machine ratings as base.

Table 3-7: Type II Suzlon®Machine Parameters.

Machine rating 2.283 MVA, 0.69 kV	
R_S	0.0027pu
X_S	0.0536pu
X_M	2.60 pu
R_r	0.0034pu
X_r	0.0564pu

Impedance of a single machine during fault condition,

$$Z_M = R_s + jX_s + jX_m // (Rr_r + jX_r)$$

$$\Rightarrow Z_M = 0.0027 + j0.0536 + \frac{j2.6 \times (0.0034 + j0.0564)}{0.0034 + j0.0564 + j2.6} = 0.10897\angle 86.9^o\ pu$$

Base impedance of the machine is

$$Z_{base} = \frac{0.69^2}{2.283} = 0.2085414\Omega$$

$$\Rightarrow Z_M = 0.10897\angle 86.9^o \times 0.2085414 = 22.725\angle 86.9^o\ m\Omega$$

In the collector circuit (34.5 kV) this impedance will be magnified due to the turns ratio of the pad-mounted transformer -- Machine impedance at 34.5 kV (referred to the collector circuit):

$$Z_{M-34.5kV} = 0.022725 \times \left(\frac{34.5}{0.69}\right)^2 = 56.8\angle 86.9^o\ \Omega$$

The impedance of the 2.25 MVA pad mount transformer referred to 34.5 kV side is:

$$Z_{PMT} = 0.0575\angle 76^o\ pu = 0.0575 \times \left(\frac{34.5^2}{2.25}\right)\angle 76^o = 30.42\angle 76^o\ \Omega$$

The total impedance of machine and transformer is about 87 Ω referred to collector circuit. With ten such units connected in parallel, as is the case in Mountain wind plant, the impedance at the collector would be about 8.7 Ω. This impedance is much higher than any cable impedance in the collector circuit. For example, the impedance of the longest cable length in the collector circuit is 0.2 Ω, which is 2.3% of the generator-transformer unit impedance referred to the collector circuit. Therefore, all cable impedances in the collector circuit can be neglected without significantly affecting the accuracy of the equivalent model for faults external to the wind plant.

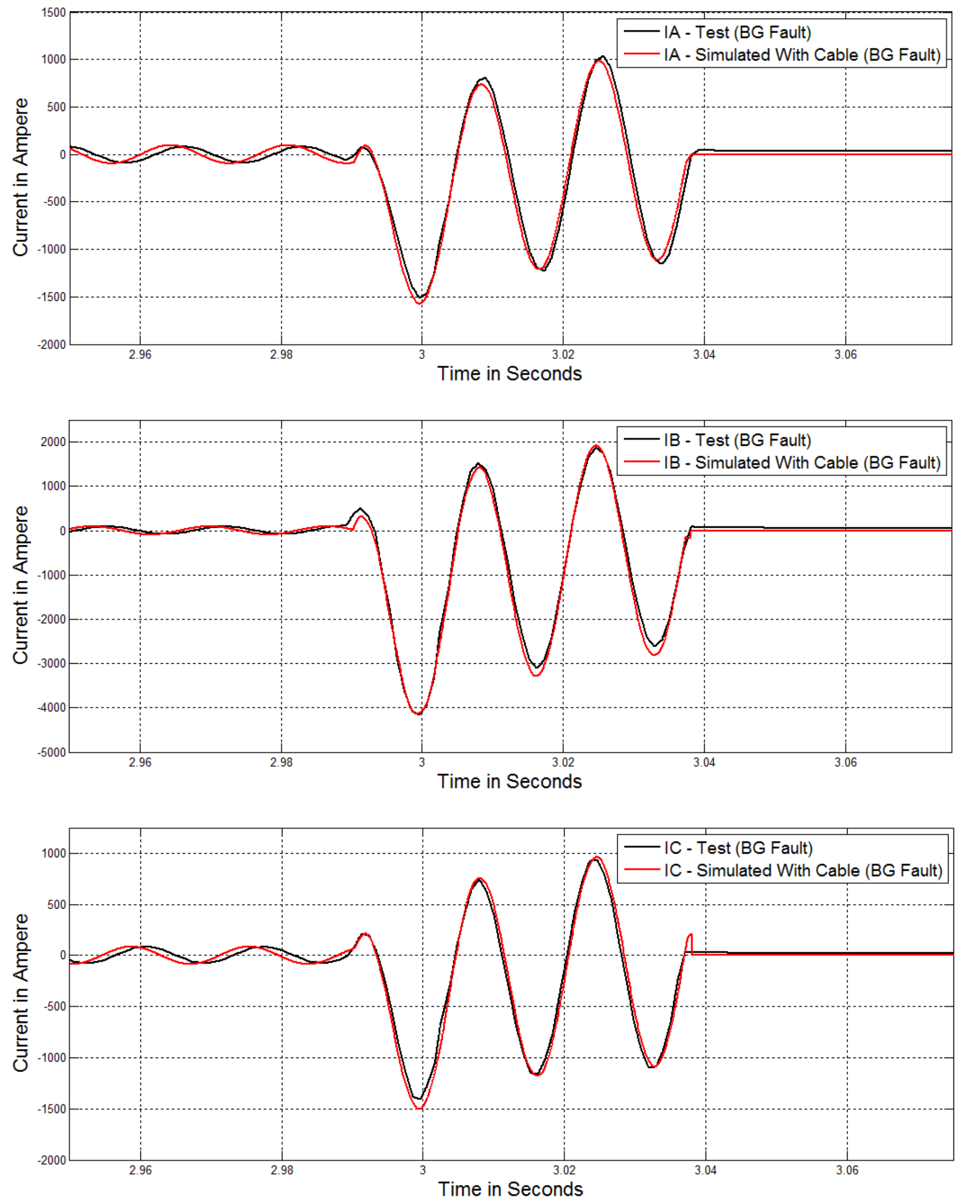

Figure 3-19: Validation of the PSCAD® model of Mountain wind plant.

In order to illustrate this point, Mountain wind plant (having 67 Type II machines) was simulated with PSCAD® in Figure 3-19 and validated using the field data for a B phase-to-ground fault. The modeling data for this wind plant can be obtained from the working group web site [8]. The real power output of each machine before the fault is included in the field data. It was matched by adjusting the external rotor resistance of each machine, so the machine delivers the logged real power at the rated slip of -0.677%. The total pre-fault reactive power output of the plant is also specified. Since it is conventional to operate the generators at unity power factor, the size of the capacitor bank at the terminal of each machine was adjusted to make the power factor unity. This resulted in a good match between the simulated pre-fault reactive power output of the plant and the logged quantities. These capacitors were kept in the circuit model throughout the simulation.

Figure 3-19 includes the test and simulation currents, showing fault contribution from the entire wind plant for a fault on the 138 kV transmission line connecting the plant to a nearby substation. The simulation was created using the models available in PSCAD® for induction generators and transformers. Cables were modeled as PI circuits. The waveforms closely match, thus validating the PSCAD® model of the plant.

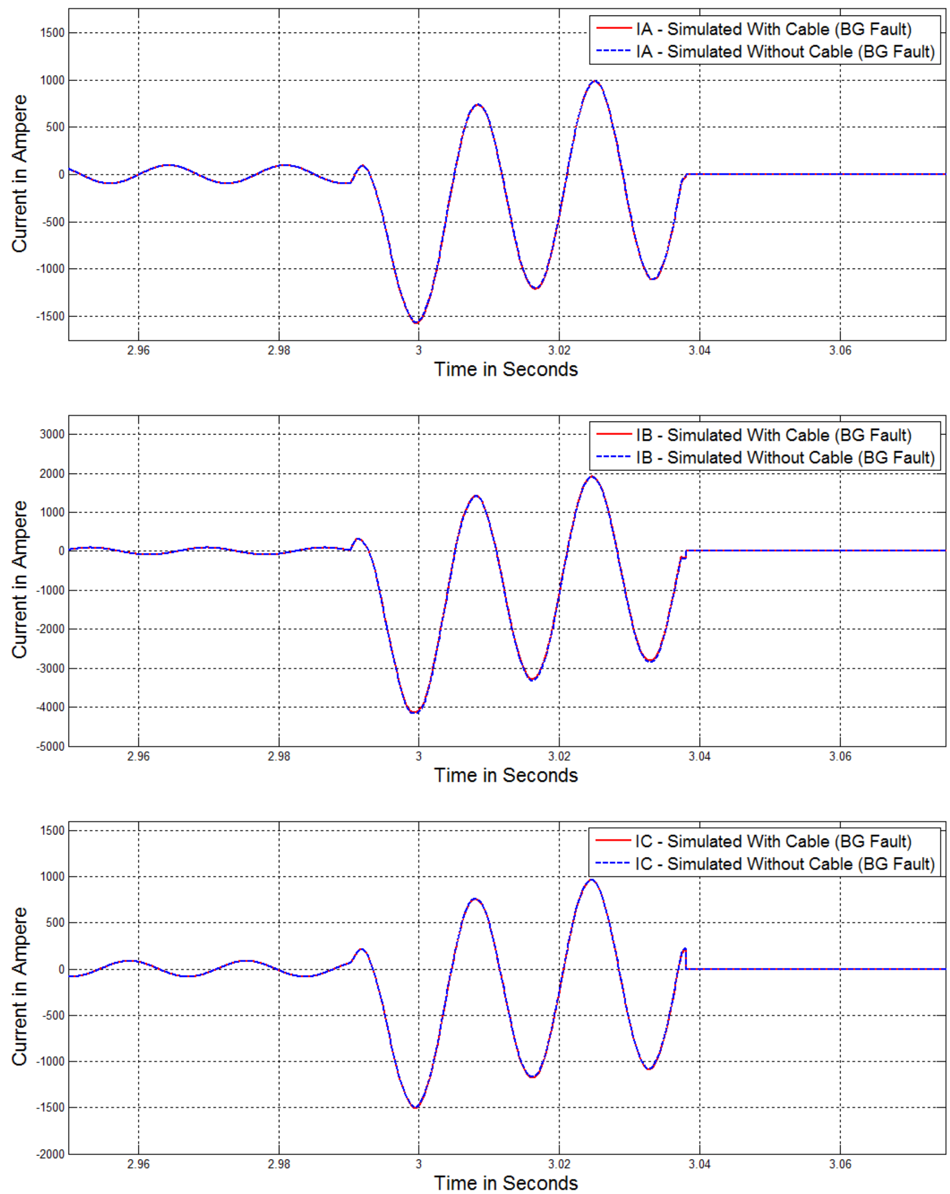

Figure 3-20: Simulated fault current contribution from Mountain wind plant with and without collector circuit cables.

In order to observe the effect of cable impedance on the fault current contribution of the wind plant, the simulation was then run after removing all cables. Figure 3-20 shows the fault current waveforms with and without cables. There is practically no difference. A zoomed view revealed that the maximum instantaneous difference between the waveforms was 1.67%, observed in the *B* phase currents at one of the peaks. This may be generally acceptable, especially because results without cables are slightly more conservative. The difference in the total impedance of the wind plant calculated with and without cable was found to be 2.84%.

3.2.3. Faults Inside the Wind Plant

For faults inside the wind plant, the cable impedances cannot be neglected. Figure 3-21 shows the total fault current for a A phase-to-ground fault taking place on the high voltage side (34.5 kV) of a step up transformer. Clearly, cable impedances play a significant role in determining the fault current.

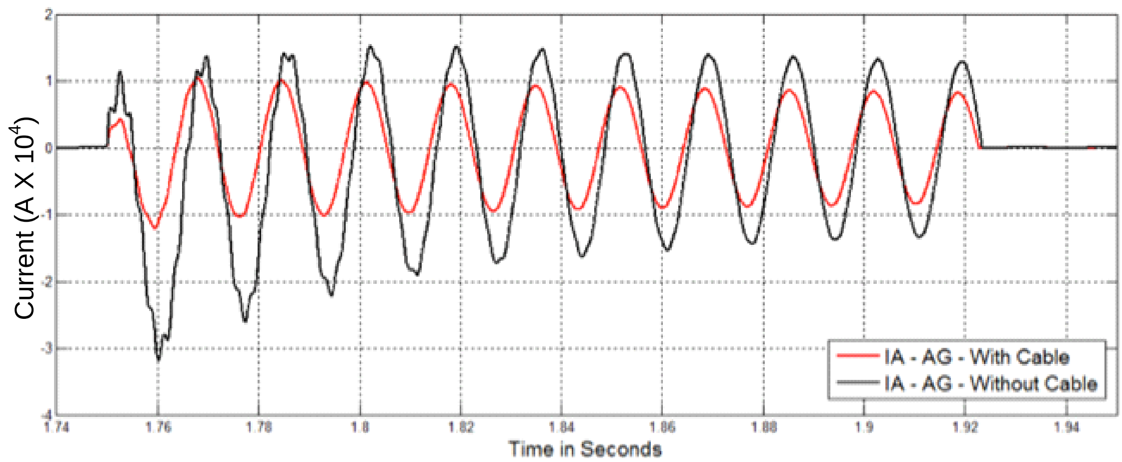

Figure 3-21: Total fault currents with and without cables for a AG fault on the HV side of a pad-mounted transformer in Mountain wind plant.

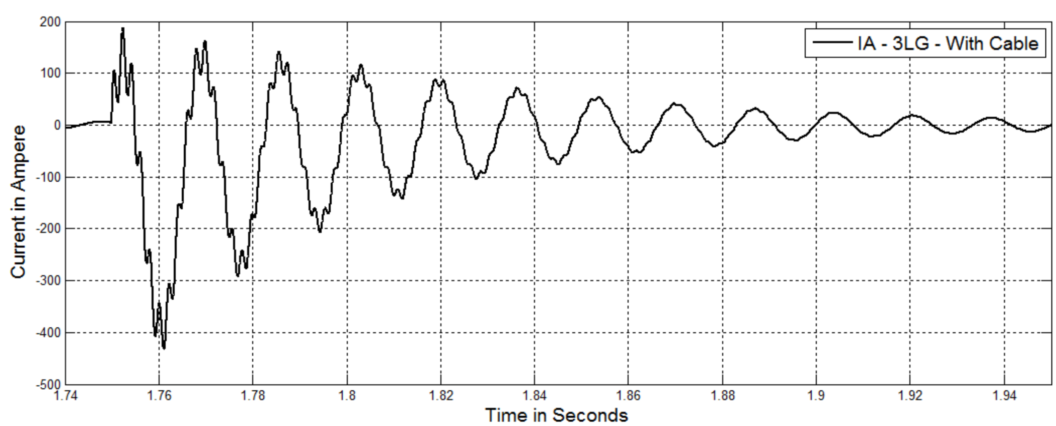

Figure 3-22: Fault current contribution from a generator measured for a three-phase fault at the HV side of its pad-mounted transformer.

In order to observe how long the fault current contribution from a generator can sustain for a fault near the generator, a three-phase fault was modeled on the high voltage side of a pad-mounted transformer. As before, all capacitors at the generator terminals are fixed. Generator contribution in one of the phases measured at the high voltage side of the pad-mounted transformer is shown in Figure 3-22. The current is characterized by a large dc offset, and is sustained for more than 10 cycles. The dc offset, however, does not prevent the fault current from crossing the zero axis, unlike the currents shown in Figure 3-18.

3.3. Type III

Type III double-fed asynchronous generators (DFG) are used in wind generation to provide variable speed operation over a wide range (typically ±30% of synchronous speed), and highly responsive to reactive power and AC voltage regulation capabilities. Since both the line and rotor side converters are solid state, the controls are very fast, typically no more than a two or three cycles to achieve full response. These machines are also commonly called double-fed "induction" generators. However their performance capabilities and fundamentals of operation are substantially different from any induction machine. The topology of a typical DFG wind generator is shown in Figure 3-23.

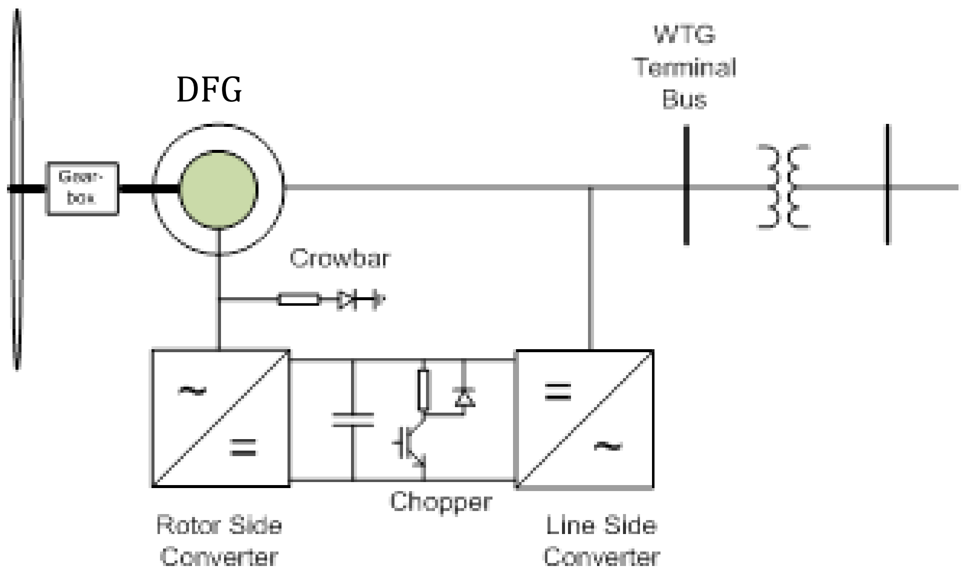

Figure 3-23: Topology of a typical double-fed (Type III) wind generator.

3.3.1. DFG Concept of Operation

Type III DFG machines have three-phase AC rotor windings with slip-rings allowing the rotor to be "excited" by an external power converter. The stator of the DFG is directly connected to the electric grid. The three phase rotor windings of the DFG are connected to a power electronic converter which provides the variable magnitude and the frequency of the rotor current. The other side of this back-to-back AC-DC-AC converter is connected to the grid. In terms of excitation, a DFG is similar to a synchronous machine, however the excitation applied to the rotor is AC with variable frequency and reversible phase rotation.

The application of an AC excitation causes an apparent rotation of the rotor's magnetic field, relative to rotation of the rotor. This apparent rotation adds to, or subtracts from (in the case of negative sequence excitation applied to the rotor) the physical rotation of the rotor. The stator field angular rotation, ω_s is the sum of the mechanical angular speed rotation of rotor, ω_m and the rotor field voltage frequency ω_r as shown in equation (3.10). The p_s and p_r are the stator and rotor pole numbers.

$$\frac{\omega_s}{p_s} = \frac{\omega_r}{p_s} \pm \omega_m \tag{3.10}$$

When the wind turbine is operating below the synchronous speed (sub-synchronous speed), the excitation applied creates apparent field rotation in the same direction as the mechanical rotation of the rotor, therefore magnetic field seen from the stator is the sum of the rotor's mechanical rotation speed plus the apparent rotation speed caused by the applied AC excitation. Likewise, when the wind turbine is operating above synchronous speed (super-synchronous operation), negative-sequence excitation is applied to the rotor, causing the apparent field rotation to be opposite of the rotor's physical rotation direction. In both sub-synchronous and super-synchronous operation, the frequency and phase sequence of the applied rotor excitation is such that the net magnetic field rotation, as seen by the rotor, is at the synchronous speed.

In sub-synchronous operation, real power must be applied to the rotor in order to create the forward-rotating apparent field rotation. This power is derived from the stator output power, via the back-to-back power converter. During super-synchronous operation, the flow of real power is out of the rotor. This power is converted to the grid frequency, and added to the power produced in the stator winding.

A DFG can appear similar to a synchronous machine, because its rotor's flux rotates at synchronous speed. However the operational behavior is quite different. The inherent characteristics of the DFG machine provide fast control of the real and reactive power output of the wind turbine. These characteristics are the controllability of the voltage-source converters used in the machine, and the fact that AC excitation of the rotor necessitates a laminated rotor design. A laminated rotor results in very short rotor flux time constants; far shorter than those of a synchronous generator. In practice, these factors yield an approximately constant source of real power and voltage regulation response that is much faster than the response of a synchronous generator; more akin to a STATCOM. A STATCOM is a solid-state voltage source inverter which can emulate an inductive or a capacitive reactance at the point of connection to the AC power network, [9]

The phase angle of the AC excitation applied to a DFG's rotor establishes the phase angle of the stator internal source voltage, primarily affecting the flow of real power. The magnitude of the excitation determines the magnitude of the source voltage, primarily affecting reactive power flow out of, or into the stator winding. Because the power converter responsiveness and the very short time constants of the laminated rotor allows extremely fast control of the applied rotor excitation, the real and reactive power of a DFG machine can be precisely controlled at high bandwidth. The control of real power plays a critical role in mitigating mechanical loads imposed on the wind turbine. The fast control of reactive power provides voltage regulation capability approaching that of a STATCOM, which is instrumental in achieving stringent low-voltage ride-through requirements imposed by most grid codes today. Because of these LVRT requirements, and the aerodynamic efficiency advantages of variable speed operation, Type III and Type IV (full conversion, described later) wind turbine technologies have largely supplanted the Type I and Type II induction generator technologies in North America and other markets.

3.3.2. DFG Balanced Fault Performance

The previous description of the Type III wind turbine generators pertains to the normal steady-state operation, as well as operation during mild to moderate faults. Severe faults cause excessive voltage to be induced onto the machine's rotor, which are, in turn, imposed on the power converter. It is not economical to design the converter to withstand the voltages and currents imposed by the most severe faults. Thus, a crowbar function is used in practice to divert the induced rotor current. There are various approaches to achieving this crowbar functionality, including:

- A shorting device (typically using thyristors) connected in shunt between the machine's rotor and the rotor-side power converter. The crowbar may include some impedance in the shorting path. This option is illustrated in Figure 3-23.
- Shorting of the rotor via switching of the rotor-side power converter.
- A chopper circuit on the converter's dc bus, to limit dc bus voltage by diversion of some or all of the current coming from the rotor is more often used in newer designs. (This is not actually a crowbar action, per se, because the rotor is not directly shorted and the rotor-side converter remains in operation, but achieves much of the same goal.)

While the crowbar function is engaged, the Type III DFG generator effectively becomes an induction generator, with fault characteristics conceptually similar to those previously explained for a Type I or Type II machine, but with practical differences introduced by the substantially different pre-fault conditions possible. Unlike a Type I or II generator, which operate with a relatively small slip, a Type III generator can operate with a large slip (typically +/- 30%). Following application of the crowbar, the potentially large slip can create significant rotor-current-induced frequency components in stator windings, producing sinusoidal fault current contributions that are not at the fundamental frequency. This condition can be observed in the first few cycles of fault current in Figure 3-24.

In the crowbarred state, the fault behavior is defined by the flux equations of the physical machine. When the crowbar is not engaged, however, the machine operates according to its control design. Unlike induction machine fault current performance, which is established by the physics of the machine, there is a wide range of possibilities in the design and objectives of Type III generator controls. Variations can be wide between different manufacturers, and even different models from the same manufacturer. Control design practices evolve over time, in response to changing grid requirements and equipment capabilities. For balanced faults of insufficient severity to cause crowbar action, some generalized and typical characteristics of Type III generator performance are:

- The generator will tend to hold constant real power output for remote faults that do not cause a large drop in voltage.
- The controls may hold the reactive power output constant for a remote fault, or the control may respond to increase the reactive power output in order to support the terminal voltage. The increased reactive power may be via a closed-loop voltage regulation function or by a programmed open-loop reactive power versus voltage magnitude characteristic.

- For more severe faults, maintaining constant power and/or increased reactive power would result in excessive current due to the decreased terminal voltage. The generator may transition to a current-limited mode. This current limit may be fixed, or may be time dependent.
- For even more severe faults, there may be precedence given for reactive output over real power output.

In addition to the variations in controlled behavior, the criteria for applying, and removing, the crowbar function can also vary widely. Different measures may be used for the crowbar threshold, such as rotor AC current or DC bus voltage, as well as different magnitude thresholds for each of these measures. In older designs, once a machine was crowbarred, it was tripped. Thus there was no removal of the crowbar while in operation. This, however, is incompatible with current fault ride-through requirements. Different designs may use different criteria for crowbar removal. In one current DFG design, a three-phase fault within a wind plant, or very near to its transmission interconnection, might result in application of the crowbar for several cycles of the fault duration with crowbar removal possible before the fault is cleared. Faults in the transmission system away from the interconnection bus result in no crowbar action with this design. Other designs may trigger the crowbar for any large drop in terminal voltage, and the crowbar may remain until the fault is cleared.

In summary, there are basically three different regimes of fault current behavior for Type III DFG wind turbines, depending on fault severity:

- Very severe faults where the crowbar is applied and not removed, thus providing the fault current performance of a simple induction machine.
- Faults of insufficient severity to cause crowbar operation, for which injected currents are controlled and performance is very similar to a Type IV (full conversion) wind turbine.
- Faults of intermediate severity where the nonlinearities of crowbar operation are critical, resulting in complex behaviors.

Figure 3-24 illustrates short-circuit current contribution of a typical Type III DFG wind turbine to a long duration[1] three-phase fault that reduces the voltage at the MV terminals of the unit transformer to 20% of nominal. In this case, the crowbar was activated for the first two cycles, and removed by the generator's controls while the fault was still present. After the removal of the crowbar, the generator contributes approximately 1.2 p.u. current continuously. This current is ordered by the controls to provide reactive support of the grid voltage, and is limited to the value shown. If the impedance to the fault were twice as large, and the machine terminal voltages depressed only half as much, the continuous fault current contribution would still be essentially the same. Thus, the controlled behavior of the Type III DFG cannot be adequately characterized by a voltage in series with a reactance.

[1] The fault was not cleared in this simulation.

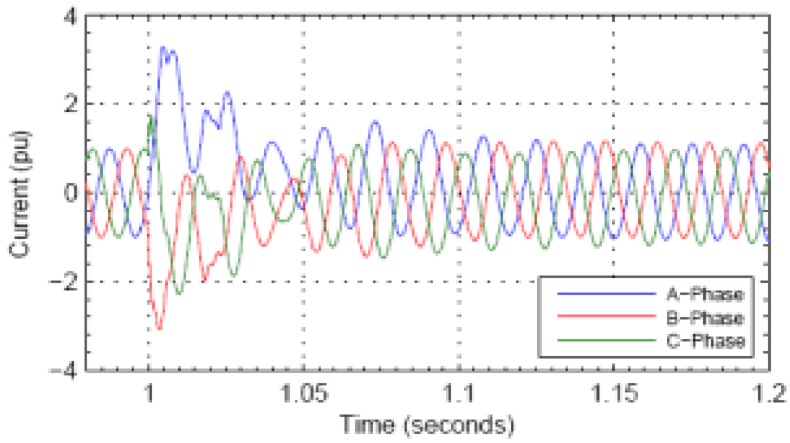

Figure 3-24: Short-circuit current from a Type III wind turbine generator for a fault reducing the voltage at the unit step-up transformer MV terminals to 20%.

3.3.3. DFG Unbalanced Fault Performance

The behavior of Type III DFG wind turbines during unbalanced faults is substantially dissimilar to the behavior of conventional synchronous and induction generators. Both of these conventional generator types appear as a Thevenin voltage source in the positive phase sequence and passive impedance in the negative phase sequence. Positive and negative sequence performance are fully decoupled in the models for conventional generators, which is a fundamental assumption of the symmetrical component analysis used in all short-circuit analysis software.

Current imbalance results in unequal current in the legs of the power electronic converters of Type III generators and ripple in the converter's dc link voltage. Because of the inherent controllability of DFG generators, they can be controlled to create a negative sequence voltage source to oppose the flow of negative sequence currents and thus attempt to maintain balanced current despite the presence of the unbalanced fault. Active opposition of current imbalance is a means to protect the power converter from excess current duty. The ability of the converter to perform this negative sequence opposition is limited by converter variables that are also affected by the positive sequence behavior. Thus, the positive and negative sequence behaviors are coupled; and the negative as well as positive sequences contain active sources. Both of these factors pose a fundamental conflict with the generator representation practices of short-circuit software programs.

A DFG that is continuously crowbarred responds to unbalanced faults just as would an induction machine, and can be readily and accurately modeled by existing short-circuit analysis tools. However, the crowbar may be engaged and disengaged during the fault, possibly in a cyclic fashion switching in and out during portions of each cycle. This cannot be modeled by any phasor-domain short-circuit analysis tool.

3.3.4. DFG Fault Modeling

The fault behavior of a Type III DFG is complicated by the inherent discontinuous behavior between the normal and crowbarred states. And, in the non-crowbarred state, the behavior is substantially the product of control designs based on a wide range of possible design philosophies and equipment capabilities. Thus, it is not possible to describe a generic short-circuit model for Type III wind turbine generators with any degree of accuracy over the range of possible fault severities.

Fortunately, the maximum fault current results from the crowbarred state, and the short-circuit behavior when crowbarred can usually be calculated using existing short-circuit analysis software and the generator's physical parameters.[2] This maximum current can be calculated using the generators sub-transient reactance, typically on the order of 0.2 per unit on generator rating. Maximum current is the limiting condition for purposes such as determining equipment fault current withstand. Protective relaying and fusing must be coordinated over the full range of operating conditions. Because a wind plant may have any number of its wind turbines operating at a given time, the short-circuit contribution varies from zero (with no wind turbines in operation) to the maximum current with all turbines operating and in the crowbar condition for a close-in transmission fault. Also, fault current contributions from Type III wind plants, particularly when operated in the controlled state, tend to be dwarfed by the typically much larger contributions from other sources in the transmission grid. Thus, detailed and highly accurate models of Type III wind turbines in the controlled (non-crowbarred) state may not be routinely needed.

Where highly accurate short-circuit modeling is necessary, phasor-domain short circuit analysis tools do not have sufficient capability, and the only recourse is detailed electromagnetic transient (EMT) simulation. EMT programs are fully capable of modeling wind turbines in great detail, sufficient to perform any needed short-circuit current analysis. While the use of such tools may be justified in certain instances, there are major shortcomings impeding their widespread use for short circuit analysis involving variable-speed wind turbines. These shortcomings are:

- Short circuit analysis is typically performed with relatively large and complex network models. EMT type programs are generally cumbersome and inefficient for large-system modeling.
- The technical communities involved in short-circuit analysis, typically protection engineers, are generally unaccustomed to using EMT programs. Use of such programs requires specialized skills.
- EMT models of wind turbines require highly detailed models of controls in order to provide meaningful results. The information needed to develop such control models is typically considered highly proprietary by wind turbine manufacturers, and is unlikely to be made available to third parties needing to perform short-circuit analysis without legal entanglements like non-disclosure agreements, as dissemination of the models could compromise the manufacturer's intellectual property.

As a result, EMT programs cannot be considered as a practical means for performing short-circuit analysis in general.

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[2] Conventional models apply when the crowbarring results in a direct short applied to the rotor, or linear impedance applied across the rotor. A non-linear impedance, such as a chopper-controlled shunt impedance across the converter's dc bus does not directly conform to conventional rotating machine short-circuit models.

3.4. Type IV

The Type IV WTG is composed of an electrical machine interconnected to the collector system through a full-scale back-to-back frequency converter. The electrical machine of this wind turbine type may use a synchronous machine excited either by permanent magnets or electrically or an asynchronous machine. As described above and in contrast to the WTG technologies presented in the previous sections, the generator of Type IV WTGs 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 is completely defined by power electronics, i.e. the full-scale converter, and not the inherent behavior of the generator. This design allows Type IV WTGs to rotate at an optimal aerodynamic speed providing extreme flexibility in generation [10] in combination with excellent grid integration characteristics such as flexible reactive power capabilities and a wide voltage and frequency operating range.

The full-scale, i.e. back-to-back, frequency converter is composed of a rectifying bridge, typically in the nacelle, DC link, and inverter either in the nacelle or in the basement of the WTG tower. The electrical representation is shown in Figure 3-25. The DC link provides the inverter the ability to be controlled and deliver output power independent of the input power of the machine within manufacturer specified voltage ranges of the DC link. The inverter is controlled to synchronize its output with the collector system frequency. Control of the inverter varies significantly among manufacturers. A unit transformer connected to the output of the inverter steps up the voltage from the range of 400 V to 690 V on the low voltage side to the collector system voltage level, typically 34.5 kV for North America and 33 kV for Europe [10], [11], [12].

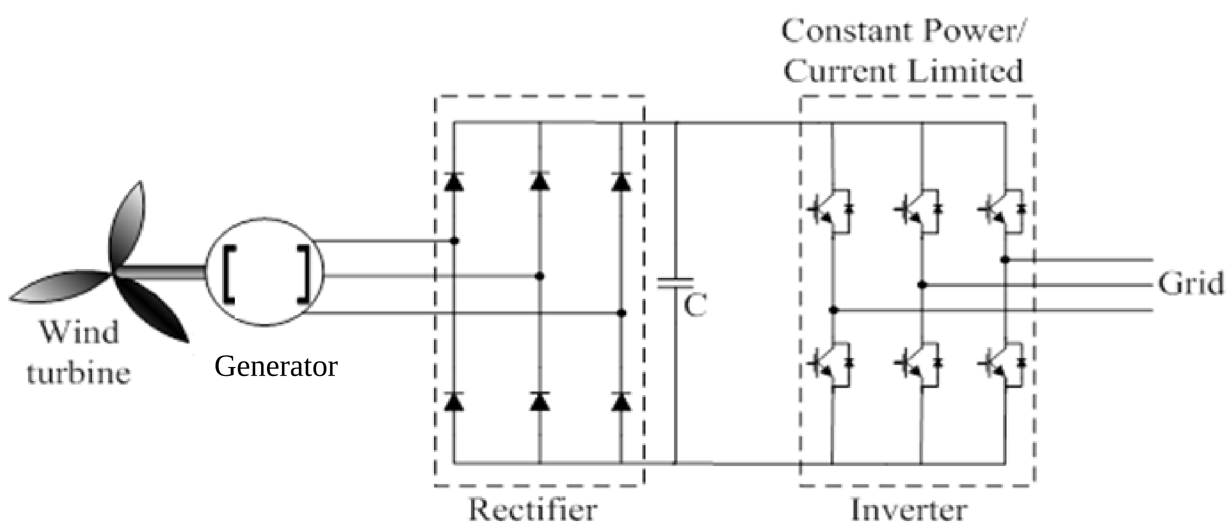

Figure 3-25: Type IV Full-scale back to back frequency converter.

Type IV WTGs can dynamically inject / absorb reactive power to / from the grid over a wide active power output range. Furthermore, most WTGs of this type can be designed to provide STATCOM-like characteristics, i.e. dynamically provide the full amount of reactive power over the entire active power range.

The voltage and frequency operating range of Type IV WTGs is usually very wide, which is especially beneficial when connecting to weak grids.

The fault response of Type IV WTGs is fundamentally determined by the control strategy implemented in the Full-Scale Frequency Converter, which varies significantly among manufacturers. Often state-of-the art Type IV WTGs only inject a symmetrical current under all operating conditions including balanced and unbalanced faults. Hence, the negative and zero sequence components of the current during a fault are non-existent. However, it should be noted that the technology allows Type IV WTGs to contribute negative sequence current, if required [13]. In most cases the inverter is controlled for constant power output with current limiting functionality. The current limiting function in many WTG technologies is often set close to the rated inverter value, e.g. 1.1 per unit, but can be higher depending on cooling and the rating of the converter. This value is then equivalent to the maximum current contribution of the WTG. In conclusion, conventional methods for steady state short circuit calculations according to, e.g., IEC 60909 [14] or IEEE Std 551™- 2006, IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems, that were designed for conventional synchronous generators cannot be applied to Type IV WTGs.

Under- and over- voltage ride through capabilities of Type IV WTGs are not limited to remaining in operation and connected to the grid during contingency conditions. Due to the power electronics, which may also include a bypass resistance to transform electric energy into heat during contingency conditions, the active and reactive current injection behavior during a fault can be controlled and does not depend on the inherent behavior of the electric generator.

In the context of the following sections 3.4.1 to 3.4.3 and unless otherwise indicated, the term “fault” in these sections of this report refers to under voltage conditions.

3.4.1. Type IV Balanced Fault Performance

Type IV WTG can usually detect a fault within 1 to 2 grid cycles. During this period, i.e. between fault occurrence and fault detection, the WTG output current will usually increase in order to maintain the active and reactive power constant at a lower than rated voltage. The maximum value of the RMS line current depends on the WTG technology, but is usually in the range of 1.1 per unit to 1.5 per unit of the rated value. The actual value of the injected current will depend on factors such as the residual voltage, prevailing wind conditions and active and reactive current set points for normal operation prior to the fault.

After a fault has been detected by the WTG control system, the current will be adjusted according to a pre-set Fault Ride Through mode, or it may be adjusted by a closed-loop terminal voltage regulation function. In either case, the performance is generally similar in that the current set point is increased in response to the fault. As an example, the grid code in Germany [15] requires WTGs to contribute additional reactive current during under as well over voltage conditions in order to dynamically stabilize the power system. The amount of additional reactive current is based on the deviation of the positive sequence voltage at fault occurrence from the 1-minute average value prior to the contingency condition. However, other markets might specify different current injection behavior during faults such as no current injection, or maintenance of the pre-fault current. If the fault response is not specified by a grid code or the utility, the manufacturer will define what the response will be. Hence, no general statement with regards to the fault contribution of Type IV WTGs can be made. Figure 3-26 provides an example of current contribution from a Type IV WTG for a three phase fault on the collector network. The fault dropped the voltage on the high voltage side of the step-up transformer to 0.2 per unit. The graph is from an EMTP simulation of a wind plant in the United States. The EMTP data model included the power electronics components and the control code for the WTG, the step-up transformer and the collector system for the wind plant. The simulation tool has been validated against full-scale tests. However, actual WTG response will be governed by the manufacturer's design of the control system.

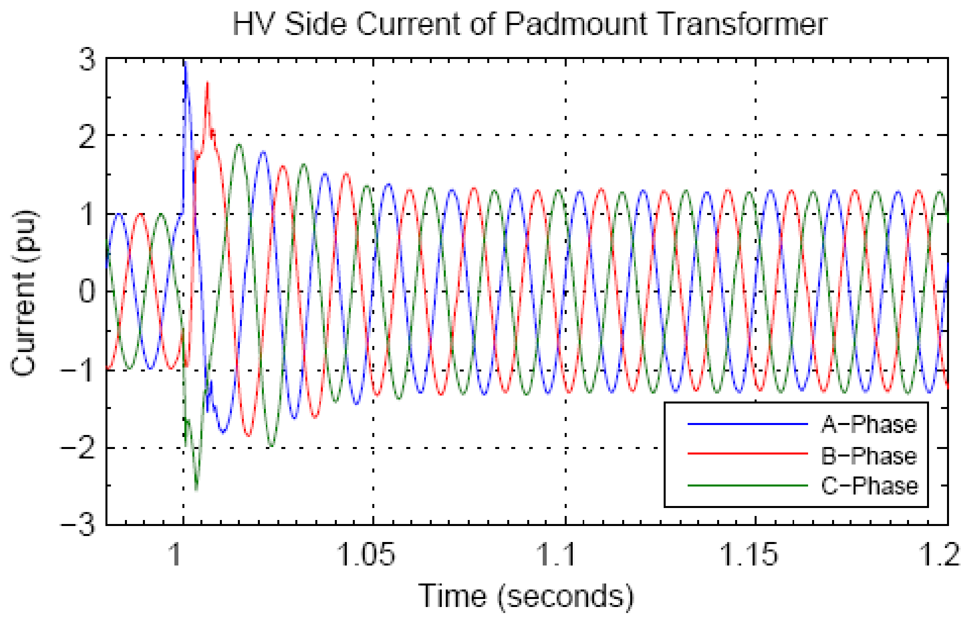

Figure 3-26: Fault Current from a Type IV WTG.

3.4.2. Type IV Unbalanced Fault Performance

Fault Ride Through performance of state-of-the-art Type IV WTGs is identical for balanced and unbalanced fault conditions. This has become more important recently since grid codes in markets such as Germany [15] and the province of Québec, Canada [16] base Fault Ride Through requirements on the positive sequence voltage, not on the line to ground voltages.

3.4.3. Type IV Fault Modeling

As described in the previous sections, the fault contribution of Type IV WTGs depends on the inverter control strategy implemented by a specific manufacturer and the applicable grid code. In this context, highly accurate short-circuit modeling may be quite difficult to achieve with the only practical alternative a compromise between accuracy and complexity of the wind turbine model.

For short circuit studies, Type IV WTGs act as a controlled current source, with current limited to protect the converter electronic devices. The operating point of a Type IV wind turbine may in principle have any value between zero and the converter maximum current.

That provides a boundary of the WTG contribution to fault current. A rough calculation of the minimum and maximum system short circuit power is then possible by taking the extreme cases: no current injection during fault and injection of maximum inverter reactive current. If the simulation software provides only the classical model of a voltage source behind impedance, usual for traditional generators, the calculation may be iterated to impose the desired current [17].

A better approximation may be obtained by considering the applicable grid code requirement regarding Fault Ride Through. A typical requirement is the injection of reactive current as a function of residual voltage [15], [18]. But also in this case some assumptions will probably be necessary as most grid codes do not specify values for active current injection during faults. The amplitude and angle of the fault current is therefore defined by each manufacturer in order to optimize the operation of the full-scale converter. Further accuracy can only be achieved using proprietary models provided by the WTGs manufacturer. However, this level of detail and complexity is usually not adopted in fault studies.

The complexity may increase considerably in the future if grid codes begin requiring asymmetrical current contribution by WTGs. In that case, finite negative sequence impedances would also have to be represented in the WTG model, instead of an open circuit or infinite impedance in the negative sequence circuit.

The following two time periods can be looked at in the context of the Type IV WTG Fault Ride Through behavior:

1) During fault detection
2) After fault detection

The current contribution during the first period depends on the residual voltage and the pre-fault operating conditions, i.e. active and reactive power output as well as the wind speed. Any value between zero amps and the maximum inverter apparent current capability are possible. During the second period, the current injection behavior of the WTG depends on the chosen Fault Ride Through operating mode [10], the residual voltage and the wind speed. Values between zero amps and the maximum inverter apparent current capability are possible. It should be noted that it is possible that the WTG output current is higher during period 1) than in period 2) and vice versa. However, usually a reasonable approximation of the extreme cases is possible by considering a few simplifications.

Some Type IV WTGs have multiple stages of generators that are tandem connected to a common inverter. These generators are mechanically coupled to the turbine shaft and electrically coupled to the inverter. The number of generators in-service depends on the wind speed at the time. The inverter generator output current will vary based on the number of generators connected to the inverter.

3.4.3.1. Case 1 Simulation: Fault contribution from WTG during three phase to ground fault on terminals of WTG

As is the case detailing Type I machines, the Type IV discussion will involve a grounded wye-delta step-up transformer. The modeled system is shown in Figure 3-27. For capturing the various contributions of fault current from the WTG, single-line to ground and three phase faults are placed on the WTG terminals.

In this study the control of the inverter is set to provide:

- Constant power output below current limiting
- Unity power factor; the current is controlled to remain in phase with the line voltage,
- Maximum current contribution of 1.1 per unit.

Depending on the fault impedance, different current level contributions are expected but with an upper limit of 1.1 per unit. This section will summarize the results of Simulink© simulation of a Type IV wind turbine contribution to a fault at the WTG terminals.

A three-phase fault of low impedance (0.001Ω) is applied to the WTG terminals at 0.4 second. The current contribution from the WTG is shown in Figure 3-28. The low impedance to ground creates a path for high current contribution. However, the current limiting function forces the inverter to only contribute the upper limit of 1.1 per unit. The black line represents the RMS of the current. This contribution can be maintained as long as turbine power is continually delivered to the DC link.

Wind Turbine

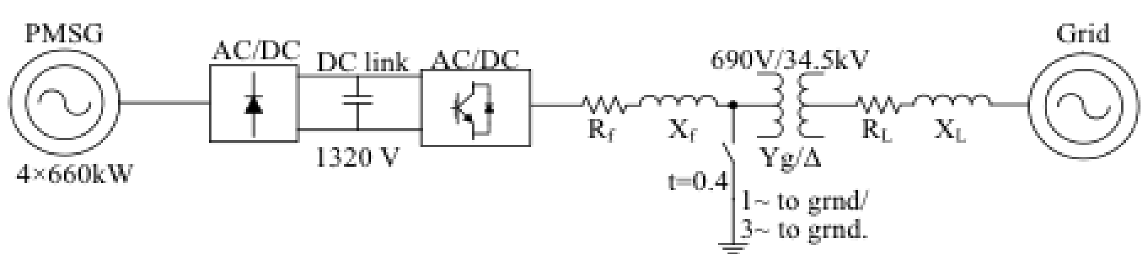

Figure 3-27: Single-line to ground/Three phase fault at WTG teminal.

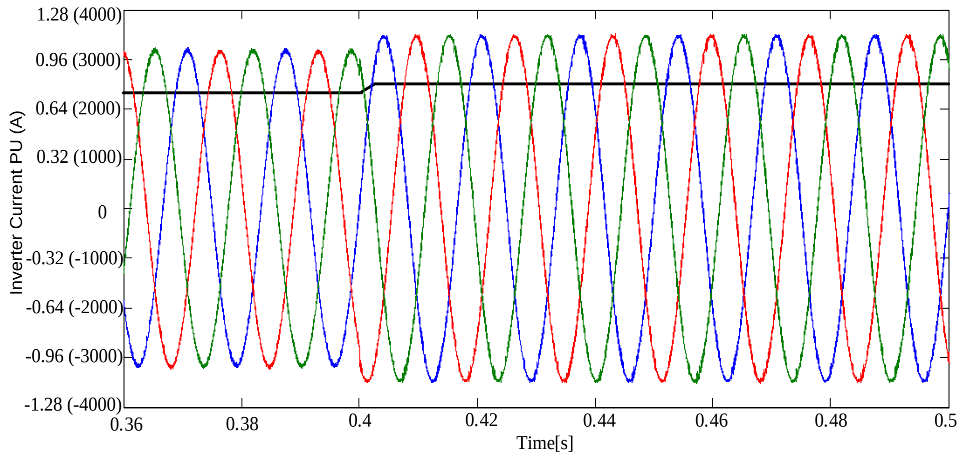

Figure 3-28: Inverter current contribution for three phase fault impedance of 0.001 Ω.

In another example, a three-phase fault is applied at the WTG terminals at 0.4 second. This time the impedance to ground was adjusted to 0.05 Ω. The current contribution from the WTG is shown in Figure 3-29. The high impedance to ground appears unnoticeable to the WTG (similar to a small load) and the converter is able to contribute the necessary fault current without increasing to the maximum contribution of 1.1 per unit.

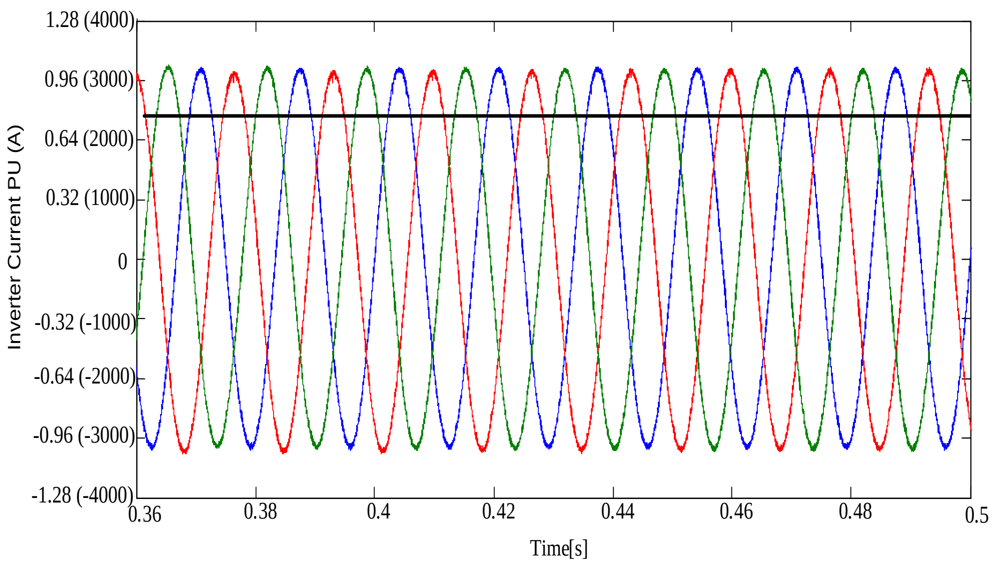

Figure 3-29: Inverter current contribution for three phase fault at WTG terminal with fault impedance of 0.05 Ω.

A three-phase fault was applied at the WTG terminals with fault impedance varying from 0.5 mΩ to 0.1 Ω. The current contribution from the WTG is show in Figure 3-30 below. The WTG fault contribution is inversely proportional to the fault impedance and varies from 1.1 per unit to 1.0 per unit. Below 1.1 per unit the WTG provides constant power output.

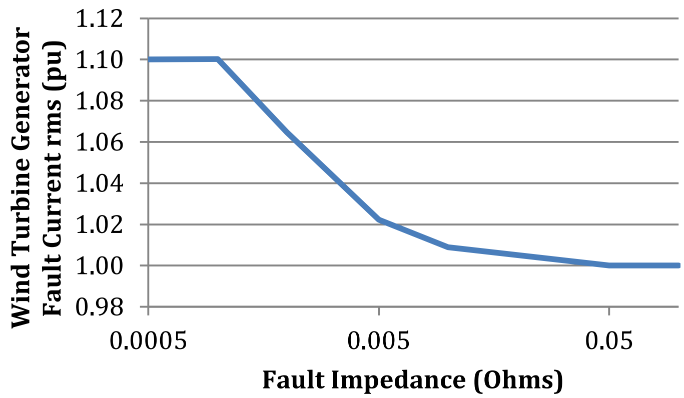

Figure 3-30: WTG fault current contribution for different fault impedances (1 mΩ to 0.1 Ω).

3.4.4. Case 2 Simulation: Fault contribution from WTG during single line to ground fault on terminals of WTG

In this case, a single-phase-to-ground fault of impedance 0.05 Ω is applied to the WTG terminals at 0.4 second. The current contribution from the WTG is shown in Figure 3-31. The constant power controller and the current limiting function force the inverter to only contribute the 1 per unit of balanced current. The collector side must capture the imbalance associated with the fault as shown in Figure 3-32.

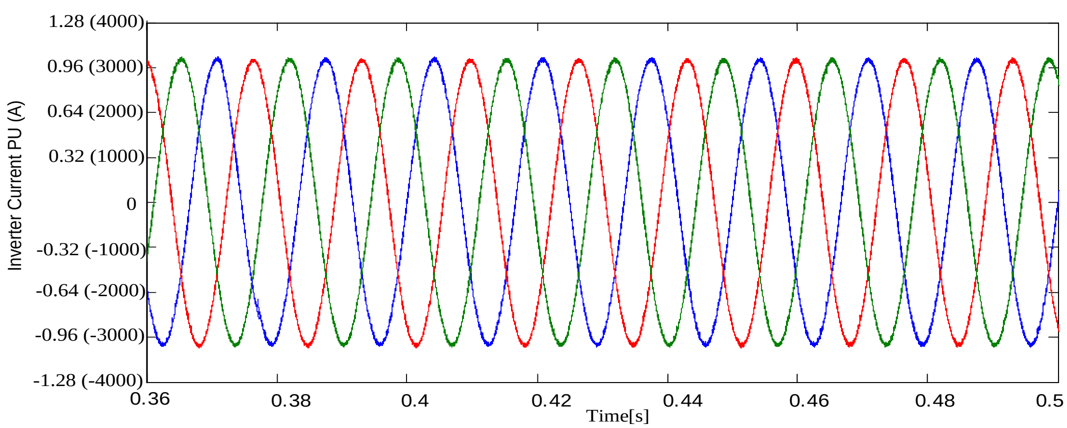

Figure 3-31: WTG fault current contribution for three phase fault at WTG terminals.

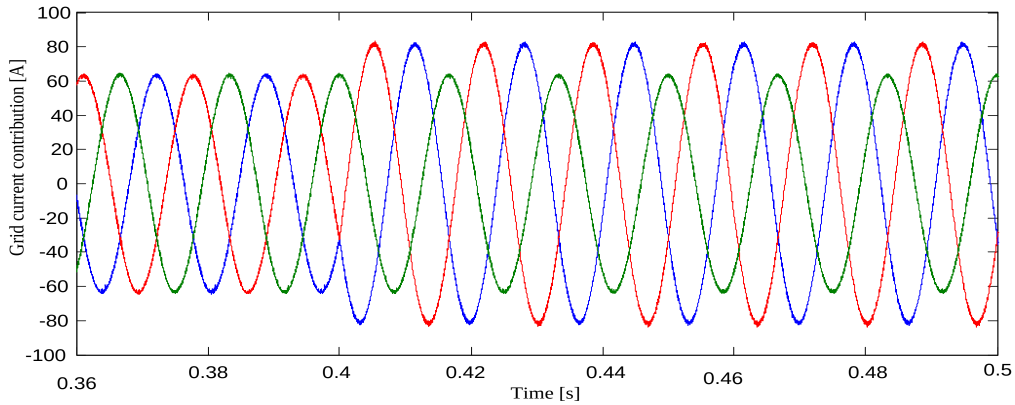

Figure 3-32: Grid current contribution for single-line-to-ground fault at WTG terminals.

3.5. Type V

Type V WTGs exhibit typical synchronous generator behavior during faults. Therefore generator contributions to faults can be calculated from the generator machine constants provided from the generator manufacturer.

These constants can be used in symmetrical component sequence networks to determine currents and voltages during faults. System protection fault studies typically use the sub-transient reactance (X_d") for the generator in the positive sequence networks. This provides the maximum fault current. Transient reactances (X_d') may also be used for time overcurrent protection which may be designed to operate after sub-transient reactance has decayed into the transient period.

Fault contributions for line to ground faults will also depend on the type of generator grounding and the step up generator transformer connection configuration. The generator neutral is typically not grounded, therefore there will be no zero sequence current contribution from the generator for a collector system single phase to ground fault, only positive and negative sequence current.

The synchronous generator excitation source may be provided by a separate exciter or permanent magnets.

4. Fault Interrupting Equipment Issues

4.1. AC Fault Levels

Power circuit breakers are used to interrupt power system faults. As such they must be rated with sufficient interrupting capacity to safely interrupt the added fault duty resulting from the interconnection of wind plants to the electrical system. Additionally, in order to bring the added power output from the wind plants, new transmission lines may be added to the network. These transmission lines are usually EHV lines, which have relatively low impedance. The overall result is that the fault duty on the system may increase. As such studies need to be done to ensure that the apparatus is capable of interrupting the additional fault current. Modern analytical programs usually provide the capability to perform fault duty analysis to determine whether the apparatus in question have the interrupting capacity required. The topography of the system needs to be defined in the database to ensure that the breakers are associated with the lines or elements they will be required to interrupt faults upon. Shorter breaker contact parting times and higher X/R ratios increase the DC component of the current to be interrupted. Therefore, the transient nature of the system should be modeled as separate R and X networks, to determine the proper X/R ratio. The reclosing cycle, when applicable, should also be included in the modeling data. The resulting study should provide the maximum duty for each element of the system under study. Care should be taken to ensure the applicable breaker design standards are used based on the year of manufacture to determine interrupting capacity. Generally those breakers built prior to 1964 were designed to interrupt total current (C37.5-1953 Methods for Determining the Rms Value of a Sinusoidal Current Wave and a Normal-Frequency Recovery Voltage) while subsequent breakers are designed to interrupt symmetrical current (C37.010-1964 and 1999, IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis).

4.2. Transient Offset to Fault Current

For various types of faults, particularly close to plants with direct connected induction generators (types I, II or III) with voltage ride through performance, there may be considerable transient offset to the waveform and fast decay of the AC component. This offset may result in several cycles of current from the wind generator with no zero crossing. For example, the simulations of Figures 3-9, 3-15, and 3-18 show several cycles of fault current before the first zero crossing. Since AC circuit breakers extinguish fault current at a zero crossing, this lack of early zero crossings may cause difficulty in fault current interruption.

One reference [19] shows that the addition of a small resistance in series with the breaker contacts will reduce the X/R ratio of the system such that a transient offset will decay so rapidly that a zero crossing within the first cycle of fault current can be expected. The reference shows only a very small resistance may be required (at least in the example presented). In some cases it is possible that the resistance of the arc within the breaker may be sufficient to reduce the offset to a level where a zero crossing within the first full cycle can be expected.

Some users may choose to add small (up to 0.1 second) delays to trip circuits of high speed circuit breakers to assist in the establishment of zero crossing in the fault current before attempting to interrupt it. The need (or not) for small delays before tripping the circuit breaker may be discussed with the wind plant developer and the circuit breaker manufacturer.

5. Wind Plant Protective Relaying

This section discusses the typical aspects of system design and in particular protective relay systems that require accurate knowledge of the fault contribution from wind powered generating plants.

As described in section 2, wind plants are electric power generation sources that consist of a varying number of wind turbine generators networked together by a collector system, typically 34.5 kV (North America) and 33 kV (Europe) feeder lines into a collector substation. Each of the collector lines have on the order of a dozen wind turbine generators connected to it. At the collector substation the collector feeders are bussed together and connected to one or more step-up transformers which boost the voltage to the level of the transmission providers' system voltage. Interconnection to the transmission system may be made at the collector substation or there may be an intervening length of transmission line between the collector substation and the interconnection switching station.

Wind turbine generators have capacities of about 1–3 MW for on-shore WTGs and about 3-7 MW for off-shore generators and operate in the range of 575 - 690 V. Each generator has a dedicated step-up transformer to raise the output to the collector system voltage. The generator step-up transformers are typically fused on the collector system voltage side and are not ground referenced to the collector system, most often being a delta connection on the collector system side. Most of the currently operating wind turbine generators function in an asynchronous manner to the transmission system but their methods of operation vary. The performance of these types of generators, and the very latest Type V machines, during system faults was described in section 3.

Regardless of the type of the WTG, these machines do not behave the same as a synchronous AC generator during a fault on the power system. Although the electrical characteristic of a synchronous generator have an apparent variation with time during a fault event; a mathematical model of a voltage source feeding though series impedance that transitions from one value to another at predictable time constants provides an accurate model of the generator. Since the time constants for the transition from one state to another are relatively long compared to the fault detection and current interrupting device operation times, most of the modeling can be done using the initial step or the sub-transient impedance. The wind turbine generators also contribute current to system faults but the magnitude of the current contributed is dictated by a combination of the electrical characteristic of the generator and the behavior of the control system controlling the power electronics that make up the total generating unit.

Earlier wind plants supplied very little reactive power to the transmission system, and during transmission line faults, in some cases relatively remote faults, the wind plant would disconnect from the system by the generators' protection circuits before the faults were cleared. Often this occurred because no low voltage ride-through requirements were in force. This type of performance is now unacceptable because unnecessary loss of significant levels of generation contributes to instability of the power system. The design of the wind plants were modified to supply reactive power to the transmission system and provide low voltage ride-through capability. To accomplish the low voltage ride-through, the wind plants include dynamic sources of reactive power. These dynamic sources of reactive power use electronic power switching to increase the reactive power output from the wind plants during transmission system faults. In some cases, the dynamic sources of reactive power are independent devices from the generators, such as Static VAR Compensators (SVCs) and Static Synchronous Compensators (STATCOMs). In other cases, the dynamic reactive power sources are integral parts of the wind turbine generators, using the inherent power electronics and control capability of the machine itself. Whether external or internal to the wind turbine generators, these dynamic sources of reactive power modify the performance of the wind plant to both provide low voltage ride-through capability and to supply current to the transmission system faults for a longer period of time.

It has proven to be a challenge for power system engineers to develop mathematical models to predict the contribution of fault current from a wind plant. On the transmission system, the primary relays will operate within one to two cycles. This time frame is typically within the time constant of the initial fault characteristic of the wind turbine generators. The fault current interruption, by the transmission line breakers, will usually take place in three to five cycles from the inception of the fault for primary protection operation. The outputs of some types of generators have decreased by this point but depending, on the point of inception of the fault, the current from the generator could have a significant dc offset which contributes to recovery voltage and potential current re-strikes while the breakers are trying to interrupt the current. If backup relaying is called upon to function, this typically occurs 20–30 cycles after the inception of the fault. The current contribution from most wind plants is likely to experience significant reduction by the time the backup relaying operates.

5.1. Collector System Protective Relaying Common Practices and Considerations

The typical collector system uses multiple feeders in a radial configuration to connect the power from the turbine generators back to the collector bus. At the collector bus, the main power transformer steps the voltage up to the transmission level.

5.1.1. Bus and Transformer Relaying

Power transformers in the size range of 20 MVA to 100 MVA typically are protected by a current differential relay, sudden pressure relay, and overcurrent relays for backup protection. Winding temperature and oil temperature relays may also be used for both alarming and tripping. Additional backup and/or redundant relays, e.g. a second differential relay, may be advisable depending on the criticality of the transformer and that of the power system to which it connects. Prompt clearing of faults may limit the amount of damage that results and may allow faster or less costly repair of the transformer, thus justifying the additional protective relaying expense. Prompt clearing of faults may also be a requirement for transmission system stability and reliability so redundant relaying may be a requirement of the interconnection agreement.

The collector bus may be included in the transformer differential zone, may have its own bus differential, or may be protected with overcurrent relaying with time delayed tripping. High speed clearing is desirable to limit damage to equipment and hazards to personnel. Including the bus in the transformer differential zone provides high-speed clearing of bus faults but can delay restoration of service following a trip, as it is advisable to test the transformer whenever a differential trip occurs to assure that there is no internal fault. A separate bus differential zone can more precisely locate the fault, avoid unnecessary tripping of the transformer differential, and provide confidence that the fault is external to the transformer. The bus may be protected by time-overcurrent relays that are coordinated with transmission side and feeder-side overcurrent devices. The inherent delay associated with time-overcurrent relays will result in a longer clearing time as compared to differential relays which operate instantaneously. However the additional delay may not be critical in smaller stations or if the overcurrent relays are used for backup. A zone interlocking scheme using relay-to-relay communications or hard wired logic contacts between relays may be utilized to trip the bus after a short time delay but to block the fast trip if the fault is detected on one of the feeders. The use of zone interlocking may be difficult to coordinate because of the WTG contribution to the fault. For zone interlocking to function, it is necessary to discriminate a fault on the bus, with infeed from the transmission system and from the generators, from a fault on one of the feeders, with the bus carrying through-fault current from the transmission system and from the other feeders. A careful consideration of the fault contribution for many different fault locations and for many different operating conditions will be required to assure correct operation of the relaying system under all conditions.

5.1.2. Grounding Transformer Relaying

Grounding transformer banks are of two types: main grounding banks and feeder grounding banks. Main grounding banks provide a system ground if the winding connection of the main transformer does not provide the system ground. The system ground must provide current sourcing capability to limit overvoltage on unfaulted phases during a line-to-ground fault and provide a source of ground fault current for detecting and clearing of the fault. Main grounding banks are typically protected by phase overcurrent relays. Because the grounding bank must be allowed to supply fault current for a line-to-ground fault, the secondary windings of the current transformers (CTs) will be connected in delta to filter the zero sequence component of the current. The grounding bank will only supply zero sequence current to an external fault, while an internal fault will have positive sequence current and possibly also negative sequence and zero sequence current. The delta CT connection allows the overcurrent relays to respond instantaneously to positive sequence or negative sequence current, indicative of an internal fault, while restraining for external faults having only a zero sequence component. For backup thermal protection of the grounding bank, a time-overcurrent relay may be included in series with the delta CT connection or a time-overcurrent relay may be connected to a separate neutral CT.

Feeder grounding banks are used in North America on each collector feeder to provide the system ground reference for the feeder once the feeder circuit breaker has tripped due to a fault, as shown in Figure 2-5. The feeder grounding banks are smaller than the main grounding bank. Feeder grounding banks are usually included in the feeder zone of protection. When design and construction is regulated by the National Electric Code (NEC), internal fuses in the grounding bank are not used because operation of a fuse will prevent the grounding bank from performing its required function as a source for ground fault current. Backup thermal protection of the feeder grounding banks is sometimes provided with a time-overcurrent relay connected to a CT on the ground connection. Protection should trip the feeder circuit breaker in case of a fault inside the grounding transformer.

5.1.3. Collector Feeder Relaying

Collector feeders typically have time-overcurrent relays for protection. Response of the relays is coordinated with other transmission side overcurrent relays and feeder side fuses or relayed fault interrupters protecting the generator step-up transformers. Breaker response must be fast enough to protect the connected equipment including the intervening underground cable. Directional overcurrent relays or a mix of directional and non-directional overcurrent relays may be used to discriminate faults towards the transmission system from faults towards the feeder circuit. Many modern micro-processor based relays include multiple levels of overcurrent elements and directional elements, so the addition of these features to the feeder protection scheme may be made at little or no increase of cost. Normal current flow is from the feeder towards the transmission grid, so any significant current towards the feeder (that is, current greater than possible auxiliary loads when the generators are not running) would be indicative of a fault. Response to faults toward the feeder should be cleared promptly to minimize equipment damage and personnel hazards. For faults toward the transmission system, the collector feeder protection operates in a backup mode. Response to faults toward the transmission system should be delayed to allow primary protection schemes to operate first, but must still be fast enough to prevent damage to the collector feeder and equipment if those primary schemes do not operate as intended.

5.2. Transmission Provider Protective Relaying Common Practices and Considerations

Transmission lines are typically configured to operate in a network in which there are multiple sources of power and fault current. The relays applied to terminals of transmission lines must be selective for faults in different protection zones and able to distinguish the difference between heavy load current and remote fault current with varying source impedances. The phase currents and voltages are nearly balanced so the presence of unbalance conditions can be an indication of a fault. Because the transmission system is not directly connected to customer loads, the voltage may be allowed to fluctuate as much as ±10%. Voltage regulating equipment is used between the transmission system and the distribution system to compensate for the fluctuation in voltage.

5.2.1. Radially Fed Transmission Lines

When wind plant generation is connected to a transmission line there are a couple of ways the POI can be configured, depending on the operation of the transmission system and the arrangement of the wind plant. Most lines in a transmission network are loop operated, in that both terminals of the line are sources into the network. However some, mostly lower voltage lines, are normally operated radially, much like the distribution system. For the radially operated line the most common configuration for the interconnection involves a breaker at the tap to the generation facility. This breaker could be at the change of ownership of facilities if the transmission provider and the generation interconnection customer are different companies. In any case, the breaker and the associated line relays remove the exposure of faults on the new line tap from contributing to the interruptions of service for the other customers connected to the line. The line relays at the tap breaker, looking toward the generation facility, must be time coordinated to operate before the line relays on the main line at the transmission provider's substation operate for faults on the tap line.

For main line faults, protective relays at the POI will need to detect the faults and disconnect the generation in a high speed manner. Since most faults on overhead distribution and transmission lines are temporary, after all sources of power to the fault are disconnected and the line is left de-energized for as short as 20 cycles, the line can be reenergized. Automatic reclosing of the line circuit breakers is applied to maintain quality of service to the customers and maintain the integrity of the transmission network. Regardless of the configuration of the interconnection, if it is connected beyond a fault interrupting device that uses automatic reclosing, the generation facility must disconnect from the transmission provider's system before the reclose attempt. Fault detecting relays are applied at the POI to detect the faults and disconnect the generation before the reclose. This can sometimes be accomplished with the independent relays at the POI, with typically distance elements, but to achieve the speed needed, the relays cannot be selective as to the location of the fault and will operate for faults on other circuits. With the configuration of a wind plant having many independent generators, the source impedance behind the point of interconnection can vary significantly, so in many cases the ability of the independent relays to detect the fault conditions is limited. Multiple relay setting groups may be needed to accommodate alternate switching arrangements of the transmission network. Although the transmission network may normally be operated radially, at least one alternate feed is typically provided to deal with non-temporary line faults and line maintenance.

If the lack of selectivity for faults beyond the line terminal at the remote transmission provider's substation is acceptable for both the generation interconnection customer and the transmission provider this would be a possible relaying option. If this lack of selectivity is not acceptable, a common solution is to apply a communication system and a pilot relay system and/or transfer trip. The local relays at the POI would still be applied as a backup, but would be time delayed to coordinate with the other line protection at the transmission providers' substation. The operation of the time delayed functions could be problematic because of the possible rapid reduction in the current output from the wind turbine generator for the fault. Depending on the characteristics of the wind turbine generators, the operation of under or over voltage and/or frequency relay functions, required in any case, maybe the most reliable backup function.

5.2.2. Hot Line Reclose Blocking

It is a good practice to install hot line blocking of the automatic reclosing at the transmission system substation. Hot line blocking prevents automatic reclosing of the breaker if the line to the wind plant is still energized. Although protection circuits are installed, including possibly transfer trip, to disconnect the generation if there is a fault on the circuit, there is a potential for failure or delayed responses of those protection circuits. If the generation has not disconnected before the circuit breaker recloses, the frequency and phase difference of the generation and the transmission system will not be the same and the out of step closing of the breaker could cause damage to the generators and other customers' rotating load, as well as guarantee an unsuccessful reclose attempt. With hot line blocking, reclosing is delayed until the generation has disconnected. The dead line check is installed at both the primary connection substation and the alternate substation (if used), to accommodate operation when the transmission network is reconfigured.

5.2.3. Loop Fed Transmission Lines

When the transmission line that the wind plant is connected to is normally loop fed, with power sources at both of the existing line terminals, other issues need to be dealt with in designing the interconnection. If a single breaker was installed at the tap point, as in the case for the radially fed transmission line, this would create a three terminal transmission line. This is a transmission line with three terminals that are sources of fault current. This configuration causes several protective relaying issues. The sensitivity of the high speed elements, or "relay reach", of the line relays at the original two terminals must be reduced and the delay of the other relay elements increased to insure that the main line will not be interrupted for faults on the tap line. This causes significant delays in clearing faults on a large section of the line from at least one terminal. Delayed clearing of faults can cause power quality or power system stability issues. It also requires delaying of the line relays on the other lines that tie into the same substations. The delays of the line relays are required to maintain relay coordination and obtain the selectivity required to maintain the network. Depending on the transmission network, it may not be possible to achieve coordination, even with delaying the other lines' relays. One of the terminals of the three-terminal line might be switched open prior to the fault, so the relays need to coordinate under all system configurations. When one terminal is open, the reach of the line relays is based on the direct impedance to the fault but when all of the terminals are in-service, the reach to the same fault is greatly increased due to the in-feed of current from the third terminal. The reach to the fault that the relay experiences in this case is the apparent impedance, which is significantly greater than the direct impedance, and varies with the magnitude of the ratio of the current supplied from the two sources. Pilot line relaying could be applied, if it did not already exist, to speed up the fault clearing. Pilot line relaying for three terminal lines is significantly more complex than for two terminal lines. In the case of a three terminal permissive over reaching scheme, a pilot trip on one terminal requires receipt of the permission signal from the other two terminals. The complexity of the scheme compromises both the dependability and the security of the line protection. The backup protection at the other line terminals still needs to be delayed in order to be selective when the pilot communication is not in-service.

Besides line protection issues, system reliability issues are also created by the three terminal line configurations. Although the maximum power output of a wind plant is not controllable, it is predictable, especially over short forecasting ranges. When a power output level from a wind plant has been established for the next hour, the loss of that power feed into the network will have impact on the network operator's ability to maintain a stable, functioning power system. For this reason, the design of the connection of a sizable wind plant to the network should be configured such that there is not a significant exposure to loss of production due to a single contingency event. A 150 MW thermal generation plant would not be tapped on a 50 km transmission line, such that a fault on any part of that line would cause a loss of production and the loss of that resource to the network. If the wind powered generating plant is to be considered a dependable power source, the same consideration needs to be given to a 150 MW wind plant as for the thermal generating plant.

For these reasons, the most common POI substation for the connection of a wind plant to transmission line is a substation configuration that avoids three-terminal lines and instead creates three separate two-terminal line sections: one each of the two original terminals of the line and a tap line to the generation facility. A three breaker ring bus is a commonly used substation configuration. The two terminals in the original line are equipped with line relays that are compatible with the existing line relays. On higher voltage networks this will typically involve a type of pilot relaying system using a radio, optical fiber, or power line carrier system.

5.2.4. Tie Line Relaying

For the line to the generation facility, a line current differential relay system is typically applied which will function correctly with the varying source impedance of the wind plant. The new transmission line between the POI substation and the generation facility can include an optical fiber cable at a reasonable additional cost and this optical fiber cable can provide a communication link for the line differential relay system as well as a path for communicating the operational and metering data needed for the operation of the generation facility.

In cases where the collector substation for the wind plant is built adjacent to the existing transmission line, the POI substation and the collector substation could have the ground mats of the two substations tied together; the two facilities may be one substation with a common fence to demarcate the different ownership of the collector substation from the POI substation. In such a case, the protective relaying for the "tie line" between the two substations need not be line relaying but could be a bus differential system. This type of protection is less complex and is typically less expensive but requires control cables to be installed between the two substations.

5.2.5. Power Quality and Islanding Relaying

When faults occur more remote to the generation facility and clearing the fault creates an island, the generation/load unbalance of the system left connected with the generation facility, will be the most effective tool to cause the disconnection of the generation facility. The under or over frequency and/or voltage relays will detect the unbalance and force the disconnection of the generation. Since the energy source to the wind plants cannot be controlled, a load to generation unbalance condition will eventually occur for any islanding condition but it is the timeliness of the tripping that is critical. When the primary source breaker trips and recloses within one second, the load to generation unbalance must be significant to assure tripping of the generation prior to the reclose attempt. It is the extreme unbalance condition during minimum load periods that can be relied upon to force the disconnection of the generation. In earlier wind plants this type of fault condition detection could be relied upon to force separation for almost any condition. Although this was good for the detection of faults, the lack of selectivity caused the wind plants to be unreliable as a network energy source. Wind plants are now required to have low voltage ride through capability so that the plants will not disconnect for conditions when the continuity of the circuit between the wind plant and the transmission network is not lost when the faulted line section is isolated.

The under/over voltage and under/over frequency protection of the system is typically installed at the POI substation; if the voltage magnitude or frequency is outside of the normal operating range this relay will operate. The operation of the relay will be communicated to the collector substation at the wind plant and result in the tripping of the collector feeder circuit breakers. Tripping the collector feeder circuit breakers instead of the main transformer MV or HV breaker is used to maintain station service power to the collector substation and facilitate restoration of the generation. There are multiple pickup levels for each condition of voltage magnitude or frequency excursion. Each pickup level has an independent time delay before producing a trip output. The pickup levels closest to nominal conditions have significant time delays, in the order of seconds. These pickup levels are set at the extreme acceptable values for continuous operation of the systems but with enough time delay to allow the controls to bring the conditions back into an acceptable range. In the case of sensitive voltage magnitude relay, the typical reason for the operation on this protection is due to the undesirable operation of the reactive power controls at the wind plant. In the case of operation of the over or under frequency relays and the less sensitive voltage magnitude relays, it is most likely an indication that an island formed due to the loss of transmission lines, i.e. the wind plant has been isolated with a section of the transmission provider's load and possibly a close balance between the generation and the load exists in the island. For more extreme excursions, the time delay for tripping is less, and is set to protect the transmission provider's and their customers' equipment.

5.3. Distribution Provider Protective Relaying Common Practices & Considerations

Unlike the transmission system, distribution lines are typically configured to operate in a radial manner with only one source of power and fault current. The phase currents are commonly unbalanced to varying degrees due to unbalanced load conditions. The relays applied to terminals of distribution lines do not have directional sensing and use the magnitude of the current to distinguish between heavy load current and fault conditions. The configuration of the distribution system is similar to the structure of a tree with a trunk and many branch lines. The size of the conductor being used is smaller the further from the distribution substation because the load current reduces. Selectivity between the different zones of protection is accomplished by time-overcurrent coordination.

The voltage on the distribution system is tightly regulated to provide quality of service required by standards and that the customers expect. A typical requirement is to keep the voltage from fluctuating more than ±5%. Controls are applied to regulators and load tap changing transformers to maintain a constant voltage magnitude even as the transmission system voltage and amount of load varies. In many cases, the controls use the current and substation voltage to maintain a specific voltage remote from the distribution substation, referred to as the load center.

As the result of the differences in the operation and configuration of the transmission and distribution systems, the addition of generation, regardless of the source of the energy, to the distribution systems makes for additional challenges. The transmission system is designed for straight forward addition of new generation sources but the distribution system is not.

In some cases, depending on the configuration of the distribution system and the capacity of the generation facility, major reconfigurations must be made to the power and protective equipment on the distribution system to accommodate the addition of the generation facility. In the process of performing the preliminary engineering for the interconnection, the first step is to develop the scope for the design of the power system that will: 1) meet the requirements for real and reactive power with the generation and load at different operating extremes, and 2) keep the consequences of the instant loss of the generation to be within accepted voltage limits. The scope for the design of the protection system can then be developed.

5.3.1. Generation Tripping Before Automatic Reclosing

Even more commonly than on the transmission system, automatic reclosing of the line circuit breakers is applied to maintain quality of service to the customers. The generation facility will need to disconnect from the distribution provider's system before the reclose attempt. Fault detecting relays are applied at the POI to detect the faults and disconnect the generation before the reclose. This can sometimes be accomplished with independent relays at the generation facility, but to achieve the speed needed the relays cannot be selective as to the location of the fault and will operate for faults on other circuits out of the distribution substation. Since a wind plant has many independent generators, the source impedance behind the point of interconnection varies significantly, so in many cases the ability of independent relays to detect the fault conditions is limited. A common solution is to apply a communication system and transfer trip from the distribution substation and/or the line recloser to the generation facility. The transfer trip circuit sends a trip signal to the breaker at the generation facility to disconnect the generation any time the substation breaker or line recloser opens. Transfer trip has the advantage that the trip circuit is very selective, providing a minimum number of interruptions to the operation of the plant.

Also similar to the transmission interconnection, it is good practice to install hot line blocking of the automatic reclosing at the substation and on line reclosers between the distribution substation and the wind plant. The hot line blocking prevents automatic reclosing of the breaker or recloser if the line to the wind plant is still energized. With hot line blocking, reclosing is delayed until the generation has disconnected.

5.3.2. Reversed Current Flow During Faults

When the generation is connected to a distribution circuit and depending on the size of the wind plant and sensitivity of the overcurrent relays in the distribution substation on the circuit to which the wind plant is connected, the current contribution from the wind plant for faults on other circuits out of the distribution substation can be greater than the pickup of the relays. If this is the case, the circuit relays will operate for faults on the other circuits due to the back feed from the wind plant. This type of operation is unacceptable because of the unnecessary interruption of load. The sensitive settings of the distribution substation relays is needed to detect faults with high fault impedance and faults located at the remote ends of the circuit. To correct this issue, the non-directional overcurrent relays must be replaced with directional units. Voltage transformers may need to be added at the distribution substation, if not already installed, as a polarizing source for the directional relays. This same condition may need to be resolved on any line recloser between the wind plant and the substation.

5.3.3. Power Quality and Islanding

Under/over voltage and under/over frequency protection is also used with the interconnections to distribution systems. Since the magnitude of the voltage on the distribution systems are held in a narrower band than on the transmission systems, the under and over voltage relay elements can be set more sensitive.

5.3.4. Reverse Power Flow Through Voltage Regulation Devices

Power flow direction is often used to indicate which side of a feeder regulator is expected to be the regulated side. The common assumption is that the side of the regulator where power flows out is the regulated side. However, when distributed generation (DG) downstream of the regulator causes a power flow reversal, this control scheme is fooled. If the regulated side is reversed due to the DG-caused reverse power flow, the tap changer can go to its limits and produce unacceptably high or low voltages on the feeder. Therefore, where the power flow through a regulator may be reversed by DG output, the controller must be capable of recognizing the reversed flow and change the regulated side of the regulator.

6. Data Requirements

6.1. Data for the System Interconnection Studies

Knowledge of contributions of fault current from a wind plant to a transmission system is required to assess the impact of the wind plant interconnection on the short circuit protection of the transmission system. Recognizing that it may be difficult to model the wind plant as a traditional constant voltage source behind Thevenin equivalent impedance, a key set of data identifying the contributions from the wind plant to the faulted transmission system under the following circumstances will need to be provided.

The data will consist of a set of currents supplied from the wind plant under various specified conditions. All currents are typically provided as fundamental frequency phasor currents in RMS amperes (magnitude and angle with respect to pre-fault A phase voltage) in the indicated time frames. Phasors for all three phase currents and all three phase to neutral voltages at the high voltage side of the collector substation step-up transformer and at the point of interconnection are required.

Currents and voltages are required for several time frames:

- Subtransient, 1-2 fundamental frequency cycles after the fault inception.
- Transient, 0.1-0.5 second after the fault inception

- Permanent, >0.5 second after the fault inception, e.g. for resistive single line to ground faults, the currents and voltages are also required 1 second after fault inception.

The currents and voltages are typically stated for the following fault types in each of the fault locations identified in Figure 6-1.

(Locations F1, F2, F3 and F4) for the three pre-fault operating cases (Case 1, 2, and 3).

- Three phase fault (ABCG) zero ohm fault impedance
- Double line to ground fault (BCG) zero ohm fault impedance
- Phase to phase fault (BC) zero ohm fault impedance
- Single line to ground fault (AG) zero ohm fault impedance
- Optionally, single line to ground fault (AG) XX ohm fault resistance (utility to specify XX)

Fault locations: (as shown on Figure 6-1)

F1 Point of Interconnection

F2 High side of the Collector Substation Step up transformer

F3 Bus of the S1 Network Source Substation

F4 Bus of the S2 Network Source Substation

Pre-fault operation cases:

- Case 1 Full power generation from the wind plant, all generators on line. All reactive power support equipment on line under voltage regulation mode.
- Case 2 Zero generation from the wind plant. All generators off line. All reactive power support equipment in the expected status for this condition and under voltage regulation mode.
- Case 3 Single contingency. Branch L2 on the transmission network out of service (or other selected contingency), and full power generation from the wind plant, all generators on line. All reactive power support equipment on line under voltage regulation mode. Neglect contributions to faults at any given location if the contingency selected results in no significant electrical connection from the wind plant to the fault location.

Note that all impedances in Figure 6-1 are in per unit on a 100 MVA base at a base voltage of XX kV (identified by the transmission provider). These impedances are provided by the Transmission Provider.

Z1S1=R1S1 + j X1S1 Z0S1=R0S1 + j X0S1

Z1S2=R1S2 + j X1S2 Z0S2=R0S2 + j X0S2

Z1L1=R1L1 + j X1L1 Z0L1=R0L1 + j X0L1

Z1L2=R1L2 + j X1L2 Z0L2=R0L2 + j X0L2

Z1L3=R1L3 + j X1L3 Z0L3=R0L3 + j X0L3

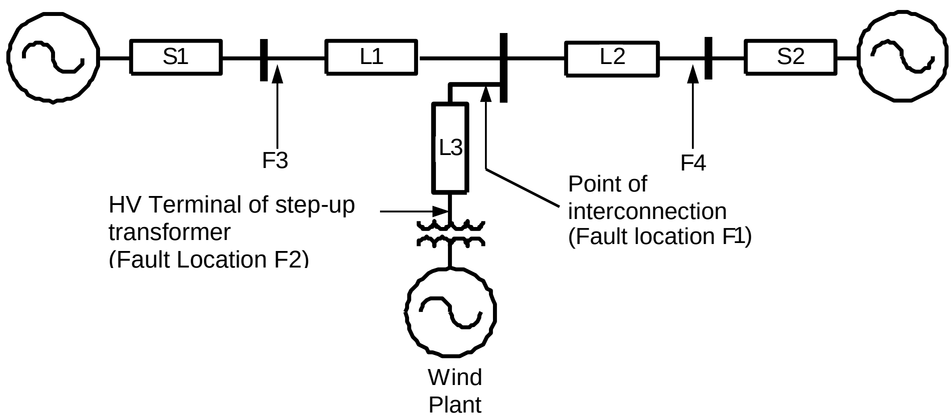

Figure 6-1: System One Line Diagram.

Impedances from the wind plant to the point of interconnection are provided by the project developer. If pre-fault power flow conditions are important to the fault study, these would also be provided to the project developer.

In addition to the various currents and voltages provided for the various faults at the indicated locations for the indicated cases, also indicate if there is a threshold voltage at the point of interconnection at which the fault current contribution changes suddenly, for instance, if a crowbar function or other electronic control device will operate when the voltage falls below a certain threshold. Specify the characteristics of the threshold voltage with respect to voltage balance, i.e., characterize the threshold with voltage depression (phase to ground) on only one or two phases and (phase to phase) on two phases, as might be expected during an unbalanced short circuit. Identify the change in characteristic of the fault current contribution when the voltage threshold is passed.

6.1.1. Generic information for Type III machines

The Type I, II, and V WTGs can be reasonably modeled as a Thevenin equivalent voltage behind a Thevenin impedance using the well known classic model. However, Type III WTGs cannot be modeled this way except during crowbar operation and Type IV WTGs cannot be modeled in this manner.

An alternative approach can provide improved accuracy compared to an assumption that the Type III generators are crowbarred. This approach specifies wind turbine fault current injection as a function of the residual voltage (V_0 or $3V_0$) at a defined point (e.g., the MV terminals of the WTG's unit transformer). This can potentially be incorporated within the framework of phasor-domain short-circuit analysis software by using an iterative solution because the residual voltage is affected by the current contribution, and the current contribution is a function of the residual voltage defined by the manufacturer's design. An initial guess is made of the voltage magnitude during the fault at the defined point (wind turbine unit transformer MV terminals). The WTG's real and reactive current contributions are determined from the defined function and set into a source representing the wind turbine in the system model. The short-circuit analysis program is assumed to be able to model a source of defined current contribution. If it does not, then the source voltage or impedance must be iterated to achieve the specified current. Once the specified current is obtained, the resulting updated voltage at the MV terminal is determined. If different than the initial guess, values of real and reactive current are determined from the tables and the process is repeated until convergence is achieved.

As with all rotating machines, the time frame must also be taken into consideration, at least for Type III wind turbines. Therefore, the contributions must be specified at specific times. As can be seen from previous sections, the waveforms are highly distorted. For the purposes of protective relaying, the fundamental frequency component (which is the quantity derived from steady state short circuit programs) is of most interest. Therefore, it is most beneficial if the manufacturer presents the current in terms of fundamental frequency components.

This approach does not require the utility to define the network to which the wind plant will be connected, and may be used to establish boundaries for the maximum and minimum contributions.

For variable-speed wind turbines, the relationship between injected current and residual voltage is nonlinear. Due to the complexities of fault performance, the determination of the current-voltage relationships requires either extensive testing, or more practically, a high resolution transient simulation model. Wind turbine manufacturers can perform whatever testing or simulation is needed to define these terminal performance characteristics and disseminate those relationships without divulging control design details.

The current-voltage characteristics are a function of time following initial fault application. Graphs of real and reactive short-circuit currents as a function of the residual voltage magnitude, can be provided for given times following fault application, e.g., first cycle for momentary currents and high-speed relay coordination, at three or four cycles for interrupting current calculations and at longer times for delayed protection studies.

Fault current magnitudes for variable speed wind turbine generators can depend on pre-fault operating conditions and control operating set points, such as power level, power factor, and pre-fault voltage. In general, short-circuit analysis is not performed with knowledge of the specific operating conditions. Therefore, the analysis must generally be inclusive of the full range of pre-fault operating condition possibilities. The search space of the operating conditions and parameters is quite large, and defining the short circuit current characteristics of the wind turbine with a single relationship is generally not possible. Therefore, a suitable approach is to provide a maximum range of currents with the minimum being assumed to be zero.

The fault current contributions from a typical Type III DFG wind turbines were obtained for several operating conditions, as an example. Simulations were performed using the Electromagnetic Transients Program (EMTP). The wind turbine generator controls, converter, parameters as well as the rest of the network are modeled in detail. To define the characteristic curve, an ideal voltage source connected to the WTG's unit transformer MV terminals, is stepped from the pre-fault value to a given reduced voltage representing residual voltage during a fault. The pre-fault operating conditions of the simulated system included a range of pre-fault voltage levels from 0.9 per unit to 1.1 per unit. Pre-fault power factor operation range included 0.90 lagging, unity and 0.90 leading for 100% power output of WTG. In addition to full rated pre-fault power, minimum power output of the WTG was also included.

The superimposed plots of the short circuit currents from all the simulated cases shows an envelope of maximum and minimum short circuit currents. These are total currents; fault current magnitudes less than rated are associated with cases where the pre-fault power level is less than rated Figure 6-2 and Figure 6-3 show the short-circuit current versus residual voltage characteristics for an example Type III design. Figure 6-2 shows currents immediately after fault application and Figure 6-3 shows currents three cycles following fault application. In both figures a minimum current contribution is shown, however, if the wind turbine is at standstill, the contribution would be zero, therefore the maximum contributions would be of most interest. These figures show "symmetrical" current contributions and therefore do not include transient offset. However the current contributions may include significant distortion due to non-fundamental frequency components. As noted earlier in this section, it would be helpful to the protection engineer if the fundamental frequency components of the fault current contributions were supplied at a time of 1 cycle (for instantaneous protection checks) and after a suitable time delay such as 0.3 seconds (for delayed protection checks).

Some caution needs to be exercised when defining voltage in a three phase system especially for unbalanced faults. Therefore, care is needed when quantifying the voltage as to whether it is the minimum phase to phase voltage or some other voltage. Caution also needs to be exercised with respect to currents in the case of unbalanced faults. Some dialog with the WTG supplier will be required to assess the machine response to unbalanced faults.

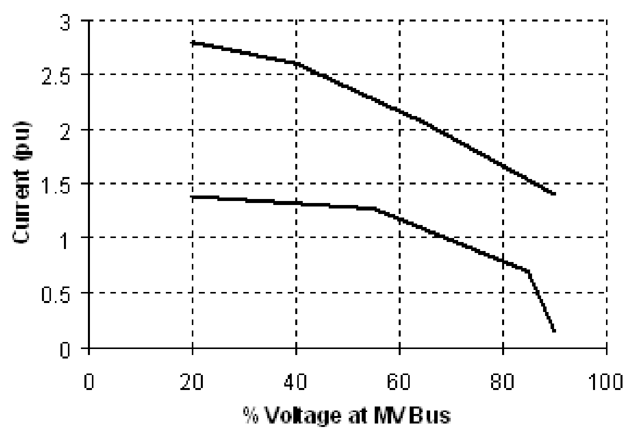

Figure 6-2: Maximum and minimum symmetrical short-circuit current magnitudes immediately after fault application, as a function of residual MV bus voltage, for an example Type III wind turbine generator.

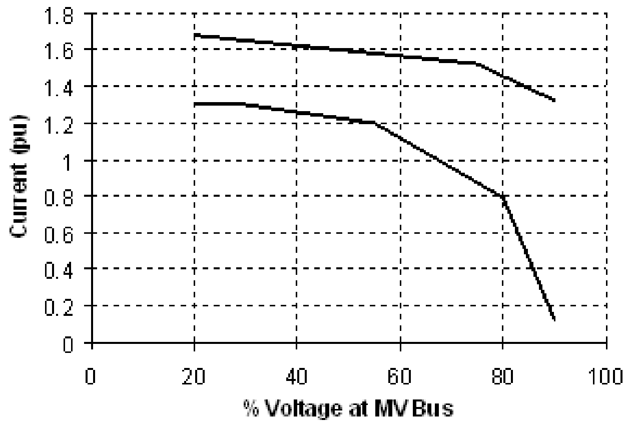

Figure 6-3: Maximum and minimum symmetrical short-circuit current magnitudes three cycles after fault application, as a function of residual MV bus voltage, for an example Type III wind turbine generator.

6.1.2. Generic Information for Type IV machines

In the case of Type IV machines, the inverter controls are generally fast enough that the fault response may be considered as constant power output with current limiting functionality, as described in more detail above in section 3.4.3. The manufacturer may be asked to confirm that the fundamental frequency current supplied to a fault may be considered constant from the fault initiation up to a several second time frame. If the confirmation is given, the manufacturer may provide the impact of terminal voltage on fault current contribution (independent of time) in a similar manner as described above for Type III machines. If the confirmation is not given the manufacturer may give the fault current contributions in multiple time frames, also as discussed above.

6.2. Data for the Collector System Design

The short circuit current contributions from WTGs are required for WPP collector system and interconnection substation protection design and coordination studies as well as equipment sizing and rating specifications.

This section describes the data that is typically required for modeling WTGs in a conventional phasor-based short circuit analysis program. These short circuit programs usually do not make any allowances for time varying fault current contributions. Because of the time varying and often difficult to predict operating state of WTG it is necessary to determine at least both the maximum and minimum short circuit current bookends for the study in question. It may also be necessary to run multiple cases representing different time frames and different WTG operating modes.

The short circuit contributions from the WTGs for faults in the WPP collector system and eventually back into the utility grid are defined by the type of generator, the nature of the fault, the winding configurations and grounding of both the generator step-up transformers and substation interconnection transformers. The short circuit characteristics vary with the type of WTG and may even vary between different designs of the same WTG type.

The short circuit representation for a WTG depends on the type of generator. Short circuit contributions from Type I and Type II generators are mostly determined by the physical characteristics of the induction generator, with the Type II generator influenced by the response of the power electronics in the rotor circuit and the switched shunt capacitors. The short circuit contributions from Type III and Type IV generators are mostly characterized by the power converter controls and design. The Type V generator contributes fault current in the same manner as other synchronous generators equipped with similar automatic voltage regulator controls.

The induction machine equivalent circuit model usually provided by the manufacturer for the Type I, Type II and Type III generators is used in motor starting studies and possibly stability studies. Sub-transient impedance, X_d", is typically used in short circuit studies to determine the machine's contribution to a fault in the period when most transmission system relays are determining their response. Type III and Type IV generators have a maximum current limit under fault conditions that the WTG manufacturer should provide.

6.2.1. Type I WTG (Squirrel Cage Induction Generator)

The Type I generator is modeled for short circuit studies as a conventional induction generator with a voltage source behind a sub-transient reactance X_d" in the case the generator has double cage or depth bars (not common in the wind industry), otherwise with the transient reactance X_d', as in Figure 6-4. A Type I WTG can contribute maximum short circuit current up to its locked rotor current which usually is of the order of 5 to 6 times its rated current (depending on the WTG size). The fault current contribution to an external three phase fault decays rapidly (within five to nine cycles) because the internal magnetizing flux cannot be sustained. The fault current contributions however for other unbalanced faults such as phase-to-phase, phase-to-phase-to-ground or single-phase-to-ground faults are lower in magnitude but can be sustained for an indefinite period by the unbalanced healthy phase voltage or voltages.

It is customary to assume that the negative sequence generator impedance is the same as the positive sequence impedance, unless specifically provided. Because the WTG is typically ungrounded the zero sequence impedance is not required.

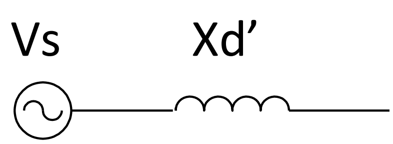

Figure 6-4: Type I WTG with squirrel cage short circuit representation.

6.2.2. Type II WTG (Wound Rotor Induction Generator with external rotor resistance controlled by power electronics)

If the Type II generator was operating at below rated slip the external rotor resistance is fully shorted by the resistor control circuit but this is not a normal operating mode. For operating conditions above rated slip the full external rotor resistance could be inserted during the fault and the resulting short circuit contribution will be lower. In this latter case this significant resistance needs to be included in series with the transient reactance, as in Figure 6-5. Both situations with and without the external resistance need to be studied to establish the range of fault current contributed from a Type II generator.

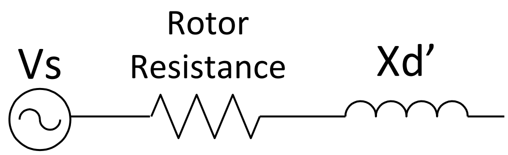

Figure 6-5: Type II WTG squirrel cage wound rotor short circuit representation.

6.2.3. Type III WTG (Double Fed Asynchronous Generator with rotor current diversion active)

The rotor current diversion is activated to protect the converter electronics during close in faults and overload conditions. As noted in section 3.3.2 this function can be achieved by different circuits which apply a low impedance circuit across either the ac or dc side of the rotor side converter. Activating these circuits effectively shorts out the asynchronous machine rotor windings. For this discussion the circuit will be called a crowbar and the activation of it is a temporary state for the WTG. In this mode of operation the short circuit model is the same as a conventional induction generator with a voltage source behind a transient reactance, see Figure 6-6. Both modes of operation, with and without the crowbar activated, need to be considered to determine the full range of fault current contribution from a Type III generator. When the crowbar is not activated the Type III generator contributes limited or restricted fault current, as in Figure 6-7. During this mode of operation the short circuit model for a Type III generator is a constant current source. Typical current limiting is at 1.1 to 2.5 times rated current depending on the specific Type III WTG design. The WTG manufacturer must specify the current limit maximum and the contributions at one cycle, i.e. the time scale in which relays make protection decisions, and three cycles, i.e. when circuit breakers are interrupting fault currents.

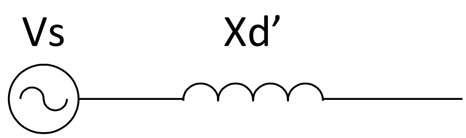

Figure 6-6: Type III WTG double fed short circuit representation, crowbar activated.

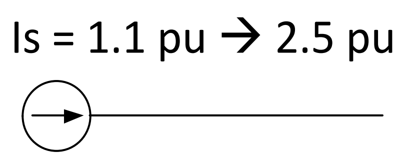

Figure 6-7: Type III WTG double fed short circuit representation, crowbar not activated.

6.2.4. Type IV WTG (Full Power Converter)

The Type IV generator acts as a limited fault current source, as in Figure 6-8. Current limiting is done by the controls to protect the converter electronics. Current is usually limited to the order of 1.1-1.5 per unit of rated current and are presently programmed to only provides balanced positive sequence symmetrical current regardless of the type of fault. Potential grid code changes may require that future WTGs contribute negative sequence current for unbalanced faults. The fault current contribution from a Type IV WTG depends on the specific proprietary design of the control system by the manufacturer. The WTG manufacturer must specify the fault current contribution level and the contributions at one cycle and three cycles, as with Type III machines.

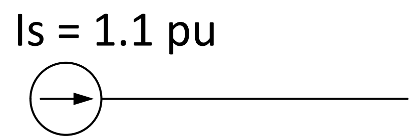

Figure 6-8: : Type IV WTG full power converter short circuit representation.

6.2.5. Type V WTG (Synchronous Generator mechanically connected through a torque converter)

The short circuit contribution from a Type V generator is the same as a conventional synchronous generator as a voltage source behind a series impedance (X_d”, X_d’ or X_d) depending on the time frame of the fault current study, as shown in Figure 6-9.

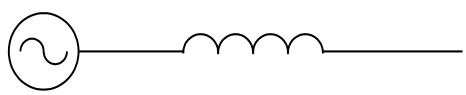

Figure 6-9: Type V WTG short circuit representation, Voltage source V_s behind a series impedance (X_d”, X_d’ or X_d).

7. Actual Performance / Examples

Voltages and currents recorded by transmission line relays applied to the transmission tie lines of wind plants were collected and analyzed to better understand how different wind plants perform during transmission system faults. Data on the operation of the individual wind turbine generator in these wind plants immediately prior to the faults were obtained from the wind plant data logging systems. Detailed configuration data of the collection systems of the wind plants, the operational data, and the results from the relay fault records, the wind plant systems were modeled using a fault study program. This modeling allowed deriving the Z1 and Z2 impedances for the WTG. The input data to the fault study program are symmetrical component impedances and the output data is steady state phasor currents and voltages on the modeled power system during a fault. Although the model is a steady state model, generator positive sequence impedances may be adjusted to simulate the system in different time frames such as sub-transient, transient and synchronous.

The fault records from the transmission line relays, besides containing the currents and voltages before, during, and after the faults also contain the RMS magnitude of the positive, negative and zero sequence currents and voltages during the recording period. These symmetrical components with the wind plant as the source behind the relay are valuable in measuring the source impedance of the wind plant during the fault. Reference [20] describes the details of the technique. The following describes the basic principles.

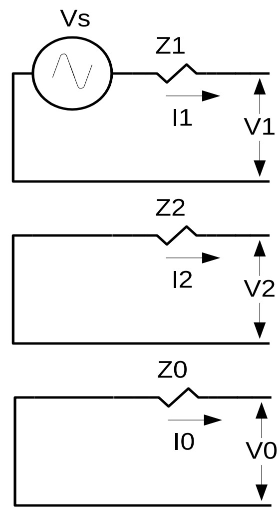

Figure 7-1: Symmetrical Component Networks.

The relay fault records provide I1, I2, I0, V1, V2, and V0. Negative and zero sequence impedance of the source behind the relay can be easily calculated using the relationship shown in Figure 7-1. The value of Z1 cannot be calculated because the voltage values are not known.

The source impedance to the relay is the series/parallel combination of the impedances of the generators, transformers and lines that make up the wind plant. Although the impedance of the transformers and lines do not vary during a fault from the normal load carrying condition, the positive sequence impedance of the generators does change. Due to this generator impedance change, there is no direct way of calculating the positive sequence impedance during the fault from the relay fault record data. The zero sequence source impedance is primarily established by the main step-up transformer. This is the transformation from the nominal 34.5 kV collector system of the wind plant to the transmission system voltage. These transformers in all of the cases studied were three winding transformers. The 34.5 kV and the transmission system windings are both wye configuration with the neutral grounded. The tertiary winding connection is a delta. Zero sequence impedance for faults involving ground was calculated from the line relay values and used to verify the impedances for the step-up transformers. With the verification of the step-up transformer impedance and assuming that the other elements of the wind plant are modeled correctly the only variable is the impedance of the generators. Negative sequence impedance of the generators in the fault study model was varied to produce a negative sequence source equal to the value calculated from the relay records.

With negative and zero sequence impedances established, the positive sequence impedance of the generators were varied to produce a matching value for the positive sequence current at a specific time during the fault. Positive sequence quantities from the line relay data contains the effects of both load and fault conditions. Comparing these values with the results from the fault study program requires preloading the model with an equivalent amount of load prior to simulating the fault.

All of the wind plants in which data of transmission line faults were collected and analyzed for this report are located in the western part of the United States.

7.1. Wind Plant 1

This wind plant has 66 – 1.5 MW Type III wind turbine generators connected to three 34.5 kV collector circuits to the collector substation. The 34.5 / 230 kV step-up transformer in the collector substation is a wye-delta-wye transformer. The 230 kV tie line between the collector substation and the point of interconnection (POI) substation is 18.7 km long. The POI substation ties the wind plant into a 230 kV network. Prior to the fault all 66 wind turbine generators were connected to the system and the plant was delivering 25.69 MW and absorbing 1.35 MVAR from the 230 kV system at the collector substation. The wind speed was 6.5 m/sec. The fault occurred on the tie line 3.5 km from the POI substation. The fault was a B – C phase to phase fault. Figure 7-2 shows the electrical configuration of the wind plant and the location of the fault.

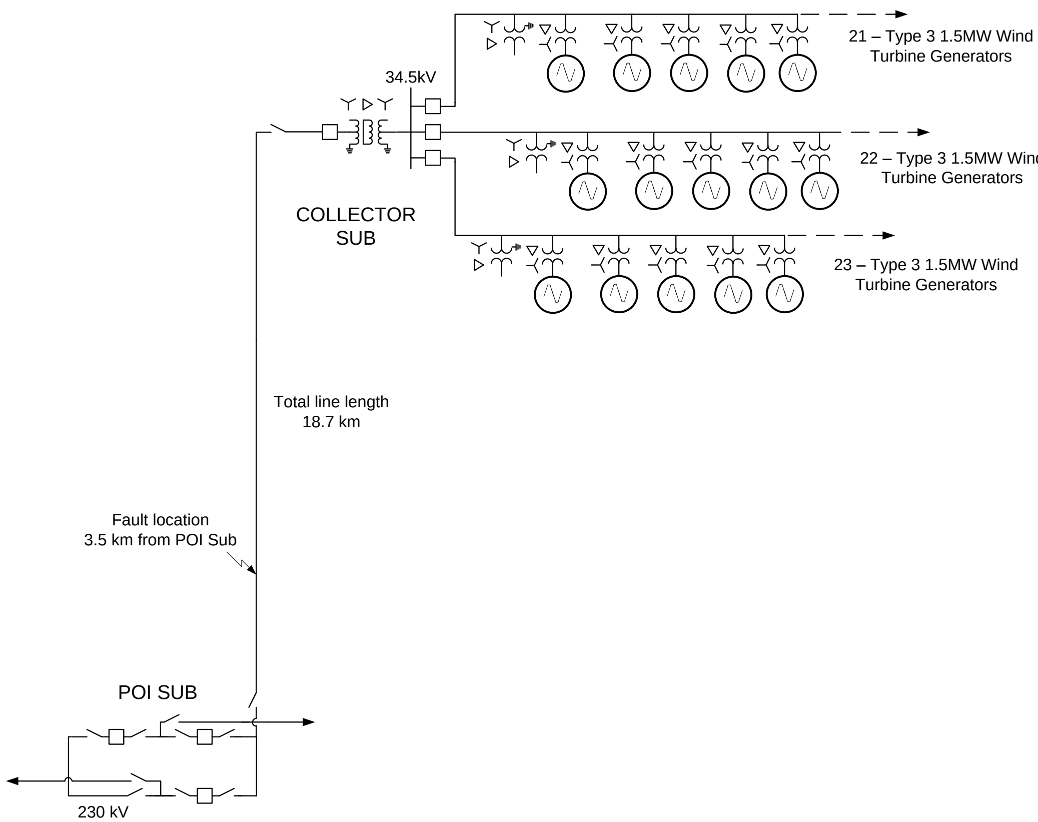

Figure 7-2: System One Line Diagram for Wind Plant 1.

The fault event was recorded by the line relays on the 230 kV tie line. The current differential relay systems that are applied to this line recorded the currents at both terminals in each relay. The following series of three figures shows some of the data recorded by the relays. The first three channels on Figure 7-3 are the phase currents from the transmission system. The second set of three channels is the phase to ground voltages on the line side of the 230 kV breakers at the POI substation. Both sets of quantities are filtered by the relay to display only (60 Hz) fundamental frequency component of the waveforms. The channels are scaled so that the RMS magnitudes for the waveforms are displayed as peak values. This is a common electric power practice dating back to the scaling of light beam oscillographs.

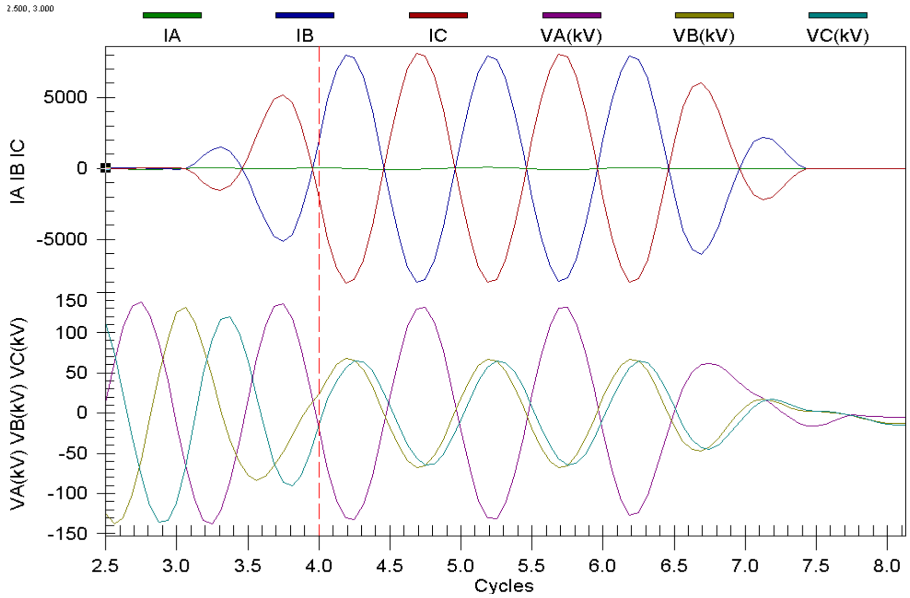

Figure 7-3: Relay Fault Record of Filtered Currents and Voltages from Wind Plant 1 POI Sub.

Figure 7-4 shows values from the same relay for the same fault but were sampled and processed by the wind plant collector substation relay and transmitted to the POI substation relay. The tie line is protected with a digital line current differential relay system, so the currents from both relays are recorded in either relay's fault record. The first set is magnitudes of the positive, negative, and zero sequence currents calculated from the wind plant filtered phase currents. The second set is filtered phase currents from the wind plant.

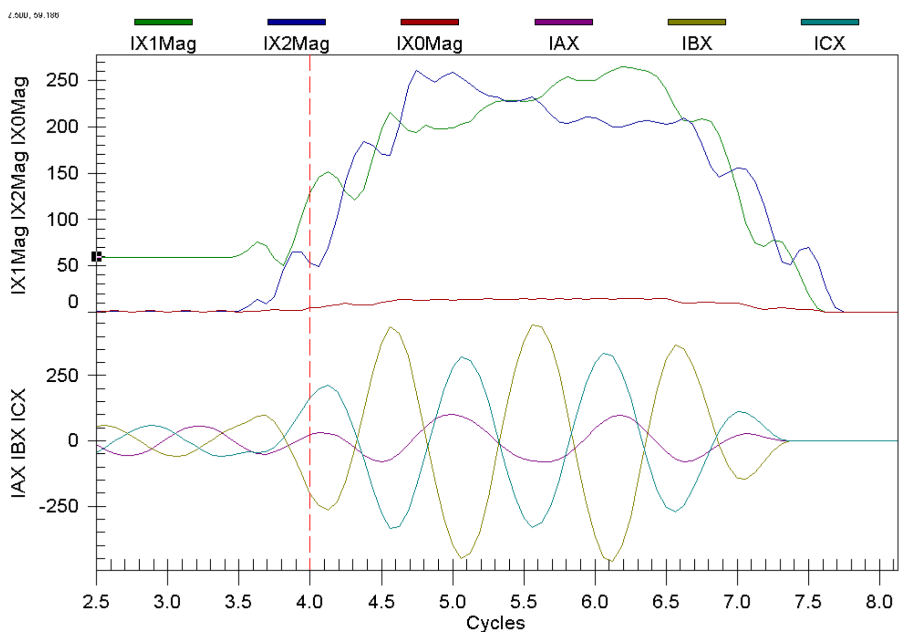

Figure 7-4: Relay Fault Record of Filtered Currents Wind Plant 1 Collector Sub.

Figure 7-5 shows unfiltered currents from the wind plant and phase to neutral voltages on the line side of the 230 kV breaker at the collector substation. The third set of three channels is the RMS magnitudes of the sequence voltages at the collector substation. The magnitudes of the current and voltage sequence qualities are used to calculate the source impedances of the wind plant to the location of the instrument transformers that the collector substation relays are connected. Although it would have been preferable to use sequence voltages calculated from filtered phase voltages, filtered fault records were not available from that location. The sequence voltages do not experience significant fluctuations in the time period that the measurements were taken, so the values should be good for this analysis. With the combined sequence source impedances calculated, the impedances of the generators are determined using a detailed fault study model of the wind plant. In the fault study model, all of the sections of the 34.5 kV lines, unit step transformers and generators are discretely modeled.

The magnitude of the positive and negative sequence currents from the wind plant are varying during the fault in an atypical manner. Typical fundamental frequency components of fault currents from rotating machines decrease with time in the positive sequence and are constant in the negative sequence. The operation of the power electronics in the Type III generators could be a cause for the atypical behavior. Since the total positive and negative sequence currents for a phase to phase fault must be equal, the varying contribution from the wind plant needs to be compensated by counter fluctuations in the current from the transmission system. The plots of the magnitude of the positive and negative sequence currents from the wind plant cross at 5.5 cycles on Figure 7-4. This is about two cycles into the fault event. This time was used to take the readings for calculating the sequence source impedance. It is clear since the magnitude of the current is varying and the magnitude of the voltage is constant the positive and negative source impedances from the wind plant is varying or a negative sequence voltage is being injected from the wind plant in addition to the positive sequence voltage.

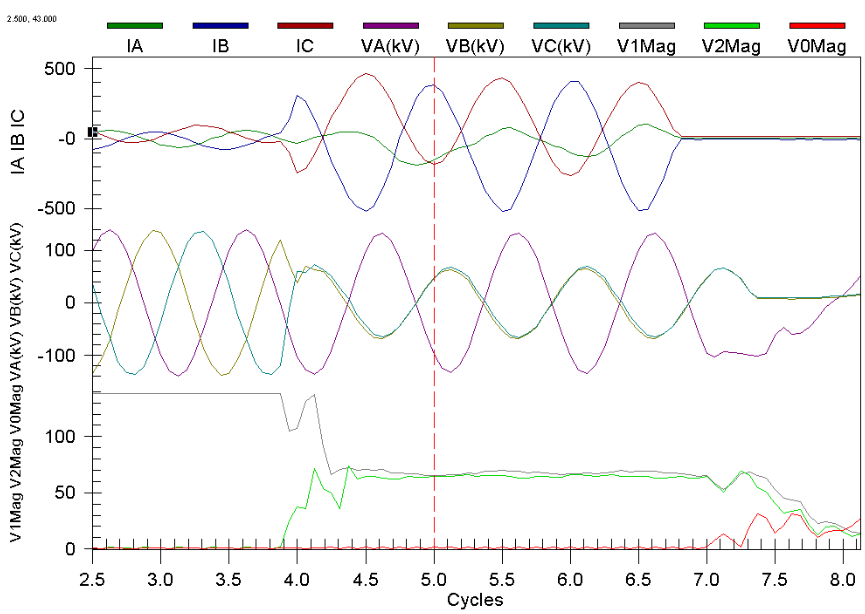

Figure 7-5: Relay Fault Record of Unfiltered Voltages & Currents and Sequence Voltage for Wind Plant 1.

At two cycles into the fault the magnitude the negative sequence current and voltage are:

I2 = 227 A and V2 = 66,246 V

The calculated negative sequence source impedance from the wind plant is 291.8 Ω.

Using the fault study model for the wind plant and assuming that the lines and transformers were correctly modeled the negative sequence generator impedance that will produce the 291.8 Ω combined source impedance is 0.36 per unit on the generators' base of 1.717 MVA.

The fault study program was again used to determine the positive sequence impedance of the generators. The positive sequence current from the collector substation at two cycles into the fault is 227 A but before the fault there was 64.3 A of load current flowing on the tie line. To compensate for the effect of the load flow during the fault, the model in the fault study is preloaded with 25.69 MW delivered from and 1.35 MVAR absorbed by the collector substation. Setting the negative sequence generator impedance at the 0.36 per unit, the negative sequence current from the collector is 227 A with no impedance in the phase to phase fault so no fault impedance is used to determine the positive sequence impedance. The positive sequence generator impedance to supply positive sequence current from the wind plant of 227 A, which is a composite of both fault and load current, was 0.4 per unit.

The results from the analysis of Wind Plant 1's fault are that at a time two cycles into the fault the Type III 1.717 MVA generators exhibited characteristics as generators with the following impedances: Z1 = 0.4 per unit and Z2 = 0.36 per unit. Using these generator impedances in the fault study program the minimum phase to neutral voltage on the terminals of the generators during the fault ranged between 0.52 per unit for the closest generators and 0.53 per unit for the most remote generators.

7.2. Wind Plant 2

This wind plant has 117 – 1.8 MW Type II wind turbine generator connected to two collector substations. Collector substation A has six 34.5 kV collector lines connecting 78 of the total 117 wind turbine generators. The remaining 39 WTGs are connected to collector substation B via three collector lines. The two collector substations are connected together by a 5.23 km, 230 kV line. Collector substation A is 5.12 km from the POI substation. The 230 kV line between the three substations is operated as a three terminal line. Three terminal current differential line protection systems are applied to detect faults on the line. Both collector substations are equipped with wye-delta-wye step-up transformers with the neutrals on both the 230 and 34.5 kV sides solidly grounded. The fault occurred on the tie line between the two collector substations, 2.67 km from collector substation B. The fault was a C phase to ground fault. 105 generators were in operation and connected to the system prior to the fault, 69 connected to collector substation A and 36 to collector substation B. Figure 7-6 is a one line diagram showing the configuration of the facility. The wind plant was feeding 168.9 MW and 8.6 MVAR into the POI substation before the fault.

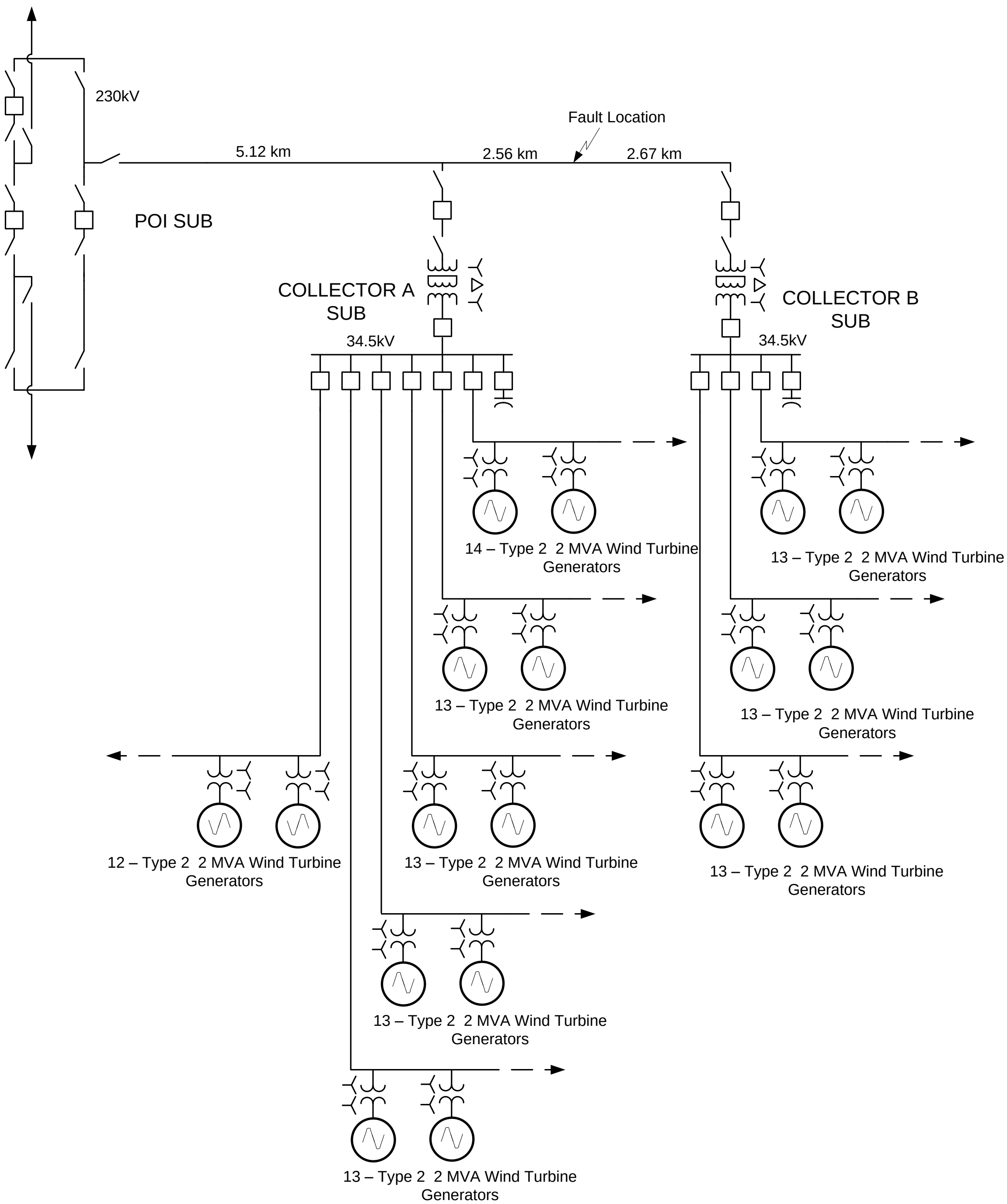

Figure 7-6: System One Line Diagram for Wind Plant 2.

The fault event was recorded by the line relays on the 230 kV tie line. The following series of five figures shows some of the data recorded by the relays. All of the quantities are filtered by the relay to display only the fundamental frequency. The six channels on Figure 7-7 are the phase currents from the POI substation and the voltage on the line side of the

230 kV breakers at the POI substation. The six channels on Figure 7-8 are similar quantities from collector substation A.

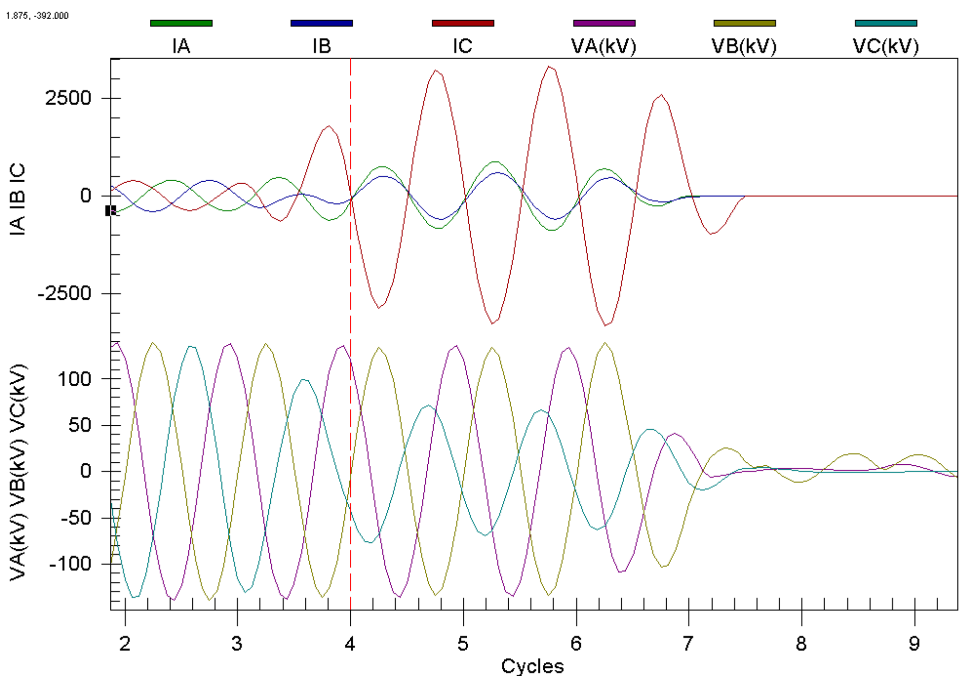

Figure 7-7: Relay Fault Record of Filtered Currents & Voltages from Wind Plant 2, POI.

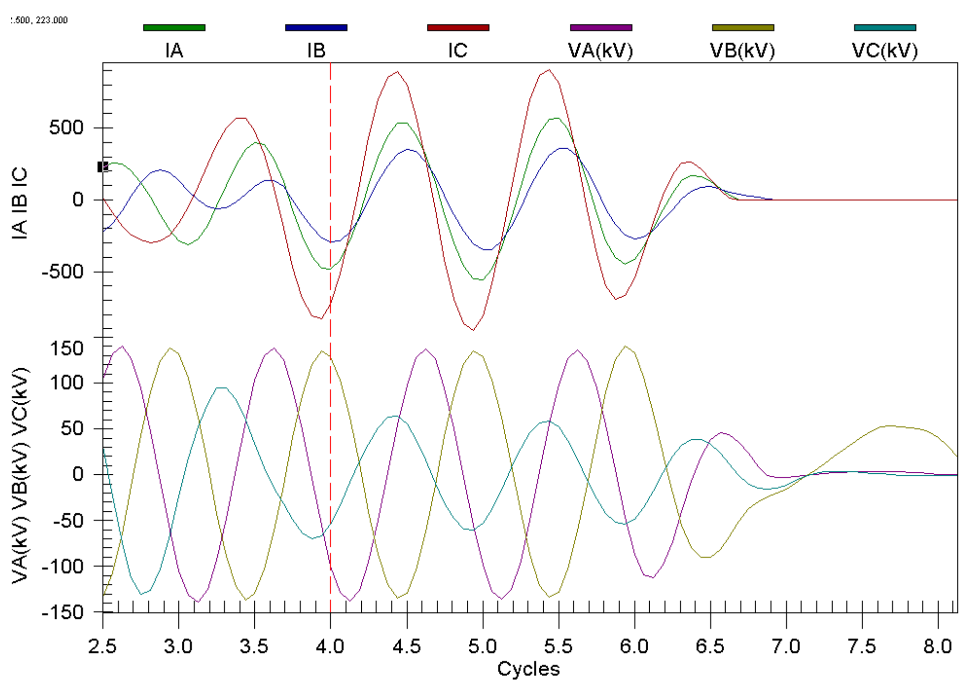

Figure 7-8: Relay Fault Record of Filtered Currents & Voltages from Wind Plant 2, Collector A.

Figure 7-9 contains two sets of channels. The first set is the filtered magnitudes of the positive, negative, and zero sequence currents from collector A substation. The second set is the filtered magnitudes of the sequence voltages from collector A substation.

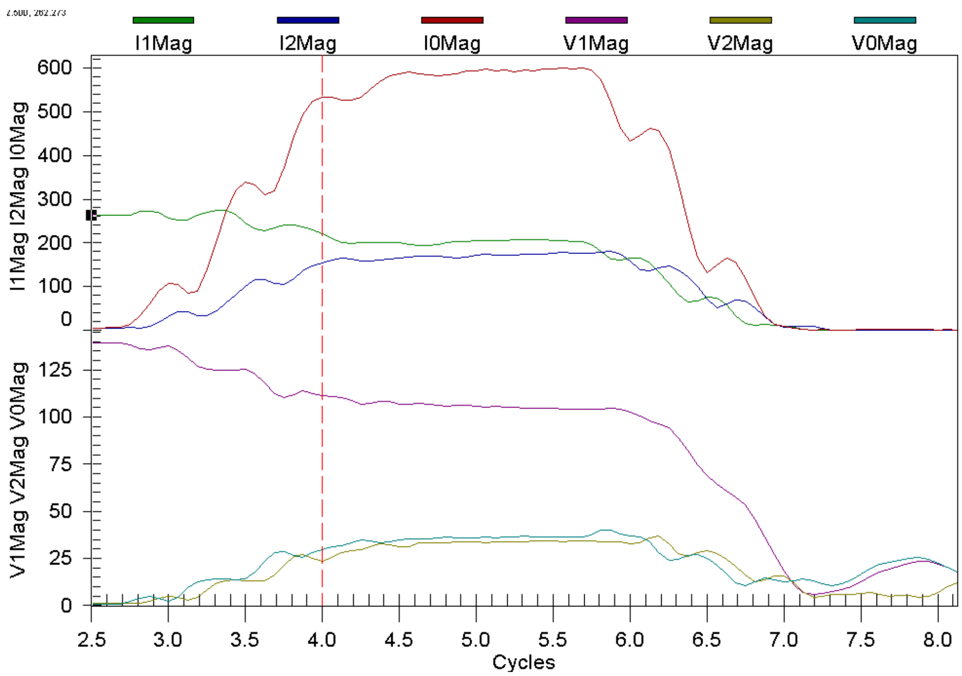

Figure 7-9: Relay Fault Record of Filtered Sequence Currents & Voltages for Wind Plant 2, Collector A.

The positive and negative sequence fault contributions from Wind Plant 2 shows more typical rotating machine behavior, with the positive sequence current decreasing with time and the negative sequence current remaining constant. Time 5 cycles on Figure 7-9 or about 2.3 cycles from the start of the fault was selected to calculate the source impedances since the values were relatively constant at this time. The following measurements were used from collector A:

V1 = 105,857 V	I1 = 204.3 A
V2 = 33,690 V	I2 = 171.7 A
V0 = 35,923 V	I0 = 593.9

The calculated negative sequence source impedance from the collector A substation is 196.21 Ω and the zero sequence source impedance is 60.48 Ω. The zero sequence impedance is the zero sequence source impedance of the 230 – 34.5 kV transformer.

Using the fault study model for the wind plant and assuming that the lines and transformers were correctly modeled the negative sequence generator impedance that will produce the 196.21 Ω combined source impedance is 0.23 per unit on the generators' base of 2 MVA.

The six channels on Figure 7-10 are the phase currents from the collector B substation and the voltage on the line side of the 230 kV breaker at the collector B substation. Figure 7-11 contains two sets of channels. The first set is the magnitudes of the positive, negative, and zero sequence currents from collector B substation filtered phase currents. The second set is the magnitudes of the sequence voltages from collector B substation filtered phase voltages.

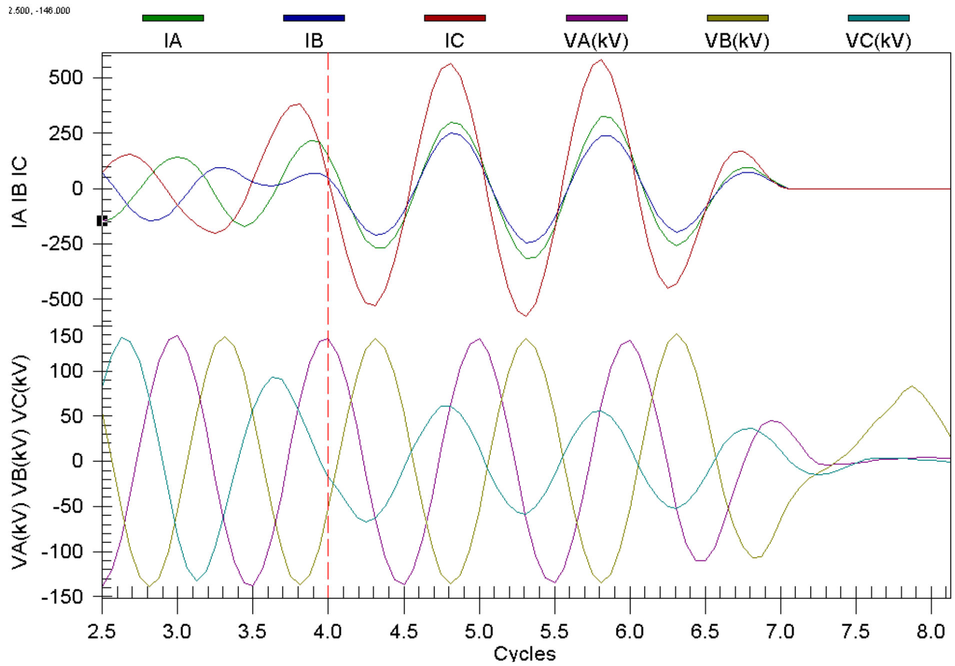

Figure 7-10: Relay Fault Record of Filtered Currents & Voltages from Wind Plant 2, Collector B.

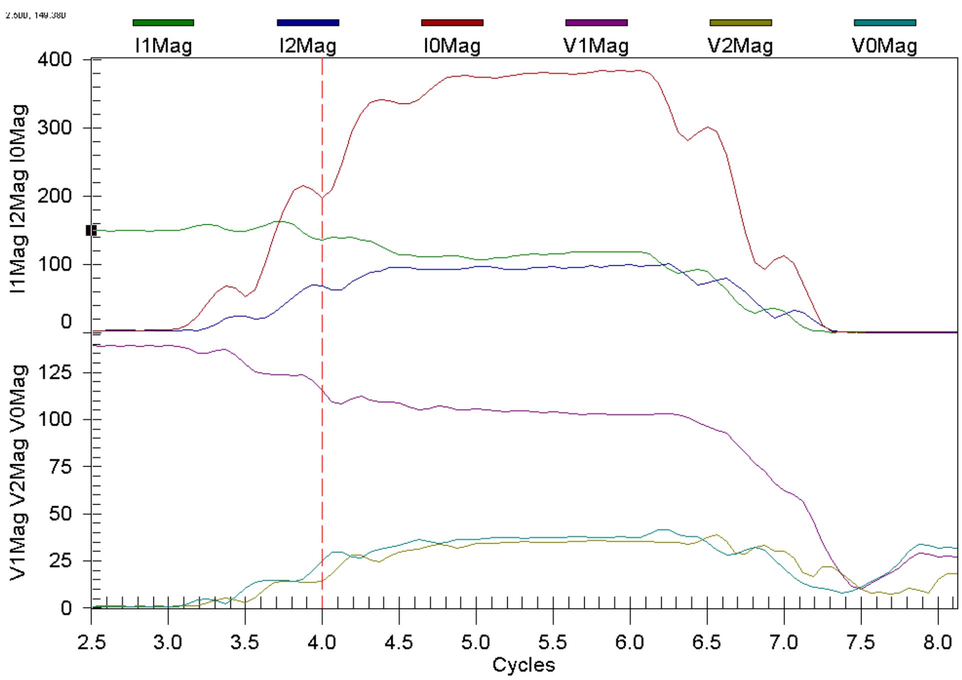

Figure 7-11: Relay Fault Record of Filtered Sequence Currents & Voltages for Wind Plant 2, Collector B.

The following measurements were taken from the sequence channels at 5.4 cycles on Figure 7-11 or 2.3 cycles from the start of the fault from collector B:

V1 = 103,717 V   I1 = 114.6 A

V2 = 34,638 V   I2 = 95.8 A

V0 = 37,436 V   I0 = 383.3

The calculated negative sequence source impedance from the collector B substation is 361.4 Ω and the zero sequence source impedance is 97.67 Ω. The zero sequence impedance is the zero sequence source impedance of the 230 – 34.5 kV transformer.

Using the fault study model for the wind plant and assuming that the lines and transformers were correctly modeled the negative sequence generator impedance that will produce the 361.4 Ω combined source impedance is 0.23 per unit on the generator base of 2 MVA.

Positive sequence impedance of the generators at 2.3 cycles into the fault was again determined by the fault study program. First the system model was preloaded to match the power output of the wind plant before the fault. Since the relay fault records contained both load and fault values, the fault study programs needed to contain both quantities for the comparison to be accurate. Next, the impedance in the fault was adjusted to match the I2 currents from the three sources: POI, collector A, and collector B. The following results were obtained with 8 Ω fault resistance:

Table 7-1: Wind Plant 2, Negative Sequence Quantities.

	Actual I2	Fault Study I2
POI	1309	1345
Collector A	172	185
Collector B	96	89

By adjusting the positive sequence impedance of the generators to match the measurement taken at 5.0 cycles on Figure 7-9 and 5.4 cycles on Figure 7-11 (2.3 cycles into the fault event) the following results were obtained for the positive sequence currents with 0.7 per unit positive sequence source impedance on the generators' base of 2 MVA:

Table 7-2: Wind Plant 2, Positive Sequence Quantities.

	Actual I1	Fault Study I1
POI	1341	1335
Collector A	204	206
Collector B	115	117

From the analysis of the fault records it was determined that the Type II 2 MVA generators exhibited a performance to this fault as generators at approximately 2 cycles into the fault with the following per unit impedances: Z1 = 0.7 and Z2 = 0.23.

7.3. Wind Plant 3

This is a wind plant with 67 - 2.1 MW Type II wind turbine generators as shown in Figure 7-12. There is one collector substation with two wye-delta-wye step up transformers. The neutrals on all of the wye windings are solidly grounded. Thirty eight wind turbine generators are connected to four 34.5 kV collector lines and one of the transformers. The remaining 29 WTGs are connected though three lines to the other transformer. The collector substation is connected to the POI substation via a 19.04 km, 138 kV line. The B phase to ground fault occurred on the tie line 13.8 km from the POI substation. Sixty one generators were connected to the system before the fault. All six of the disconnected generators are from the collector lines feeding into the #1 transformer. Just before the fault 14.05 MW was being delivered from the collector substation and 5.06 MVAR was flowing toward the collector substation.

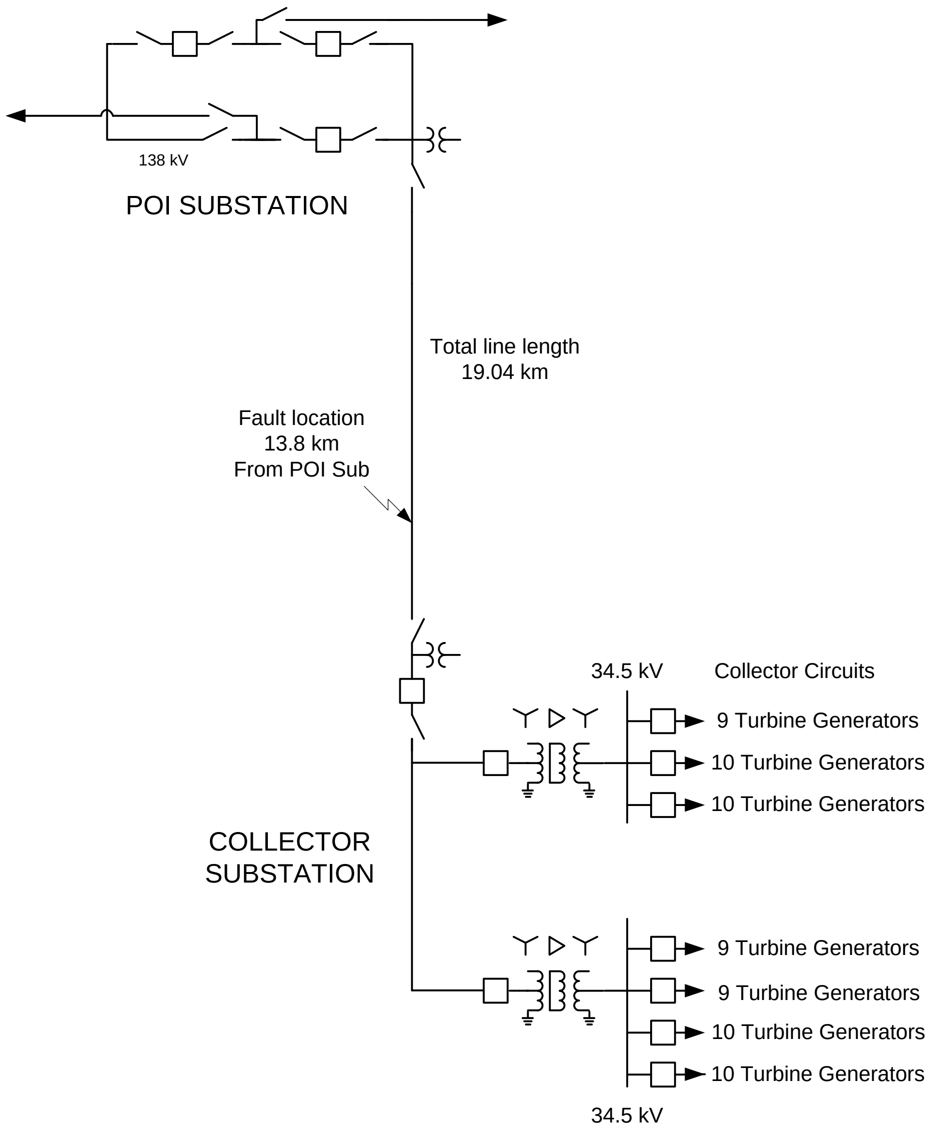

Figure 7-12: System One Line Diagram for Wind Plant 3.

The fault event was recorded by the line relays on the 138 kV tie line. The following series of five figures shows some of the data recorded by the relays. The six channels on Figure 7-13 are the phase currents from the POI substation and the voltage on the line side of the 138 kV breakers at the POI substation. The six channels on Figure 7-14 are similar quantities from collector substation except the POI channels are not filtered and the collector substation channels are filtered.

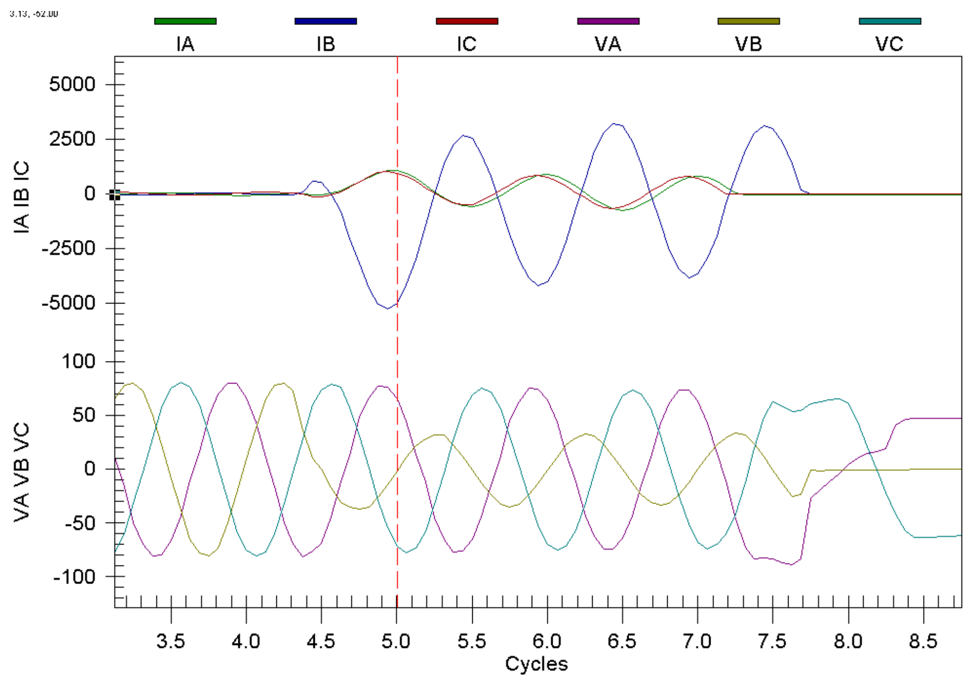

Figure 7-13: Relay Fault Record of Unfiltered Currents & Voltages for Wind Plant 3, POI Sub.

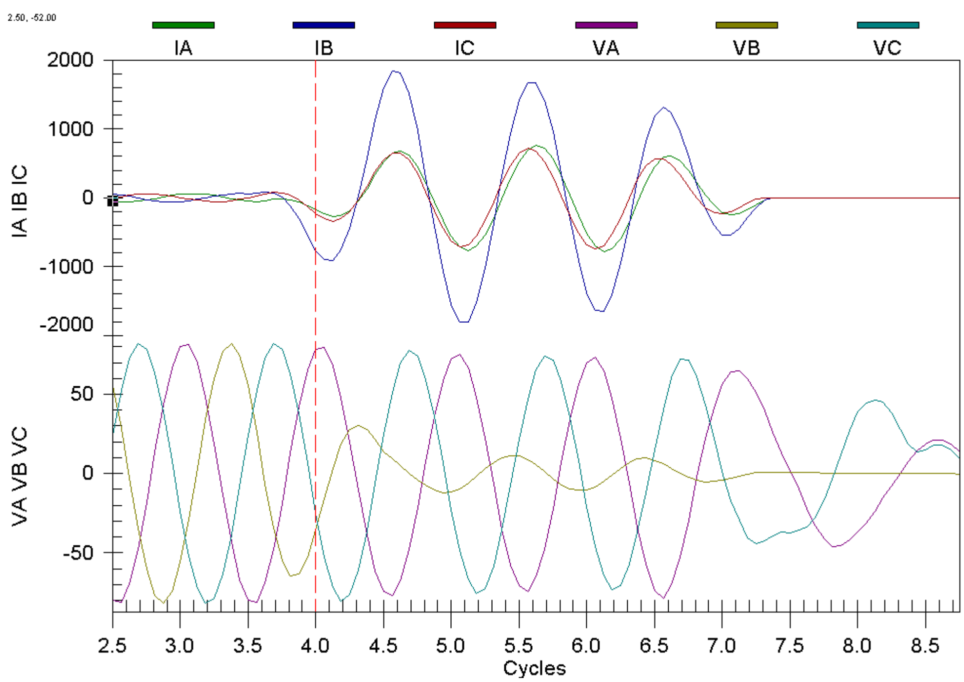

Figure 7-14: Relay Fault Record of Filtered Currents & Voltages for Wind Plant 3, Collector Sub.

Figure 7-15 contains two sets of channels. The first set is the magnitudes of the positive, negative, and zero sequence currents from collector substation filtered phase currents and the second set is the magnitudes of the positive, negative, and zero sequence voltages from the filtered phase voltage on the line side of the 138 kV breaker at the collector substation. It can be seen that the positive and negative sequence contributions are again more typical of rotating machines than the Type III generators at Wind Plant 1.

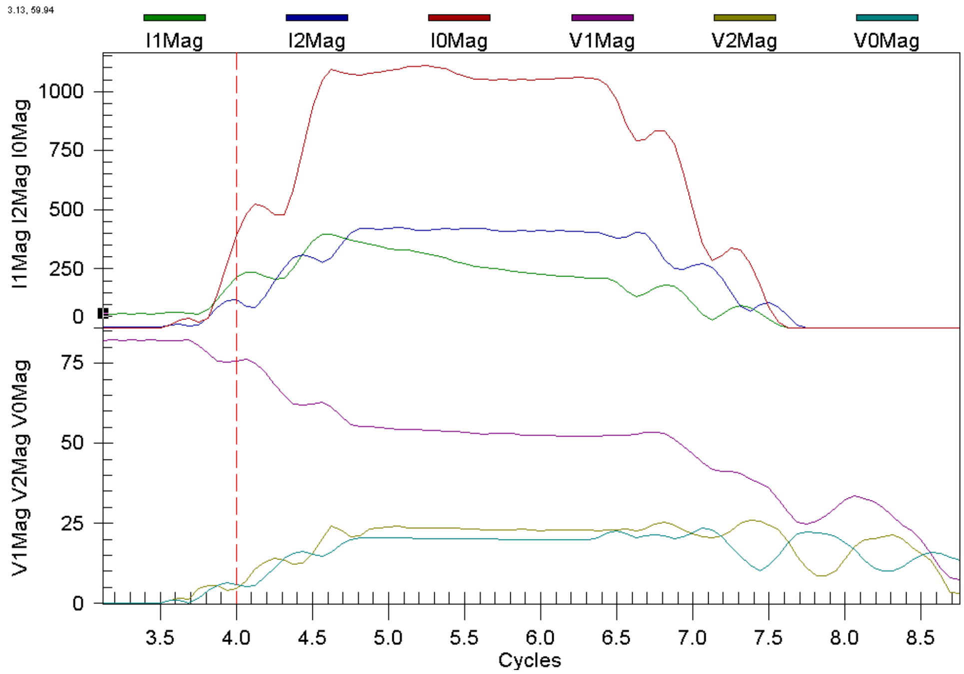

Figure 7-15: Relay Fault Record of Filtered Sequence Currents & Voltages for Wind Plant 3, Collector Sub.

The following measurements were taken from the sequence channels from the collector substation at 5 cycles on Figure 7-15 about 1.5 cycles into the fault event, when the positive sequence current was constant for a short period:

V1 = 54,541 V	I1 = 335 A
V2 = 23,750 V	I2 = 421 A
V0 = 20,420 V	I0 = 1090 A

Calculated negative sequence source impedance from the collector substation is 56.4 Ω and the zero sequence source impedance is 18.7 Ω. The zero sequence impedance is the zero sequence source impedance of the 138 - 34.5 kV transformers.

Using the fault study model for the wind plant and assuming that the lines and transformers were correctly modeled the negative sequence generator impedance that will produce the 56.4 Ω combined source impedance is 0.222 per unit on the generators' base of 2.283 MVA.

Positive sequence impedance of the generators 1.5 cycles into the fault was again determined by the fault study program. The fault study program was loaded to match the pre-fault power output of the wind plant. The fault impedance was adjusted to match the I2 currents from the two sources: POI and the collector substation. By adjusting the fault resistance it was determined that the resistance in the fault was 2.5 Ω. Since the 335 A of positive sequence current includes both the load and fault current, load was added to the fault study program model to match the pre-fault load flow. Using the 2.5 Ω fault resistance and adjusting the positive sequence impedance of the generators it was determined that the positive sequence impedance of 0.36 per unit on the generators' base will deliver the positive sequence current recorded by the relays when combined with the negative and zero sequence impedance already determined.

From the analysis of the fault records it was determined that at time 5 cycles on Figure 7-15 (approximately 1.5 cycles into the fault event) the Type II 2.283 MVA generators exhibited a performance to this fault as generators with the following per unit sequence source impedances: Z1 = 0.36 and Z2 = 0.222.

7.4. Wind Plant 4

This is a wind plant with 11 – 1.5 MW Type III wind turbine generators. There is one collector substation with a 34.5 – 115 kV wye-delta-wye step up transformer. The neutrals on all of the wye windings are solidly grounded. There is one 34.5 kV collector line with the 11 WTGs connected to the one transformer. The POI and collector substation are the same facility. The 115 kV transmission line feeds distribution substations as well as connecting the wind plant to the transmission network. The line from the POI/collector substation to network substation is 10.7 km long. Prior to the fault all 11 wind turbine generators were connected to the system and the plant was outputting 17.7 MW and 3.2 MVAR into the transmission system. The fault occurred on the line to the network substation, 3.8 km from the network substation. The fault was an A phase to ground fault. Figure 7-16 shows the electrical configuration of the wind plant and the location of the fault.

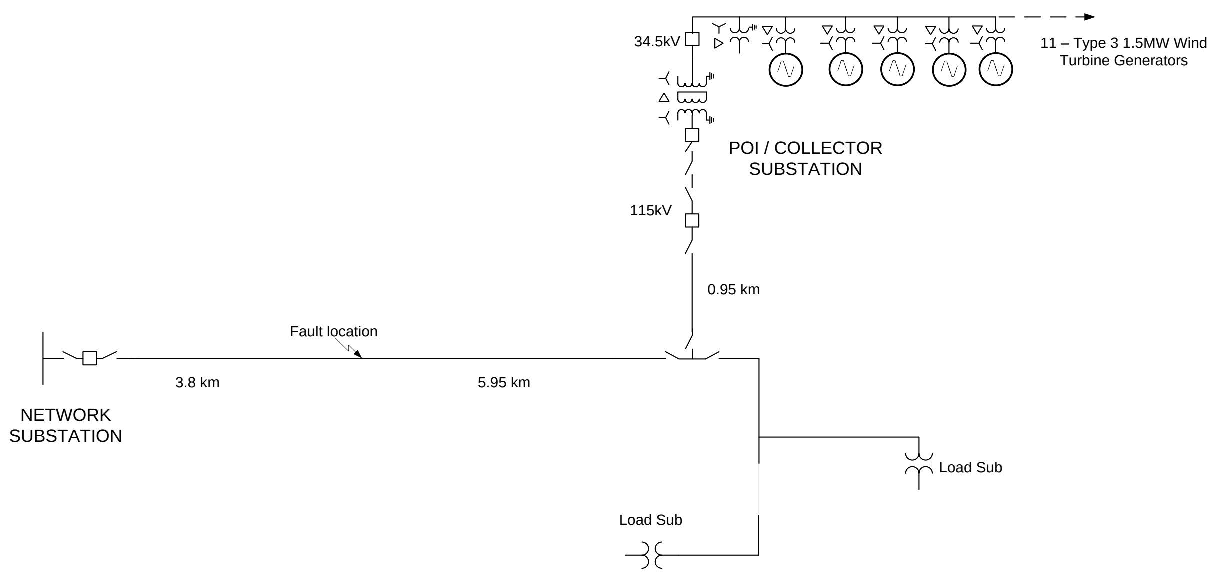

Figure 7-16: System One Line Diagram for Wind Plant 4

The fault event was recorded by the line relays at the network and the POI/collector substations. The following series of four figures shows some of the data recorded by the relays. The six channels on Figure 7-17 are the unfiltered phase currents from the network substation and the voltage on the 115 kV bus at that substation. Figure 7-18 are the filtered values of the same quantities as are in Figure 7-17.

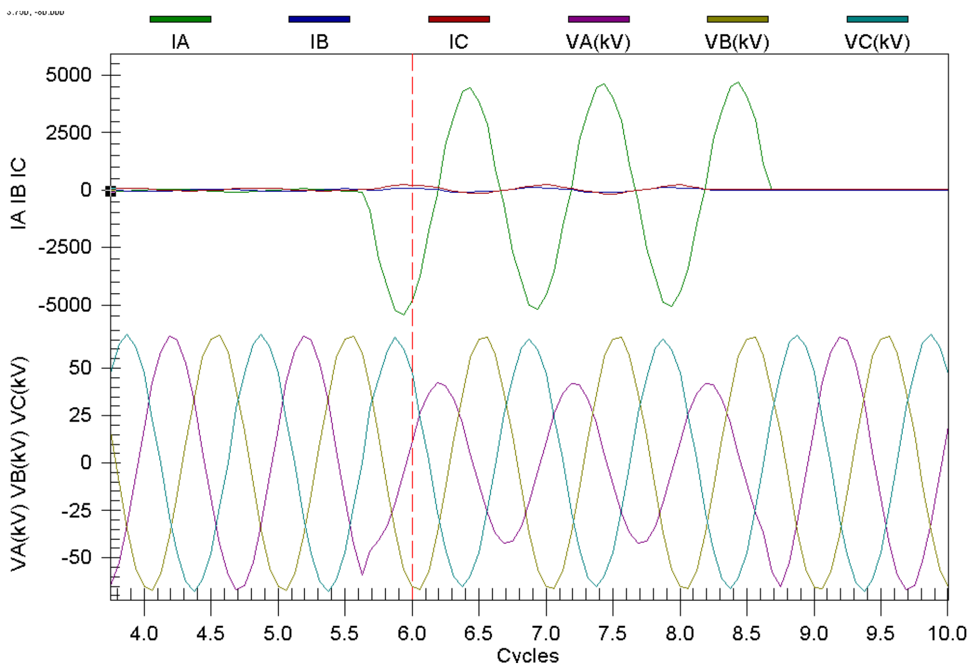

Figure 7-17: Relay Fault Record of Unfiltered Currents & Voltages for Wind Plant 4, Network Sub.

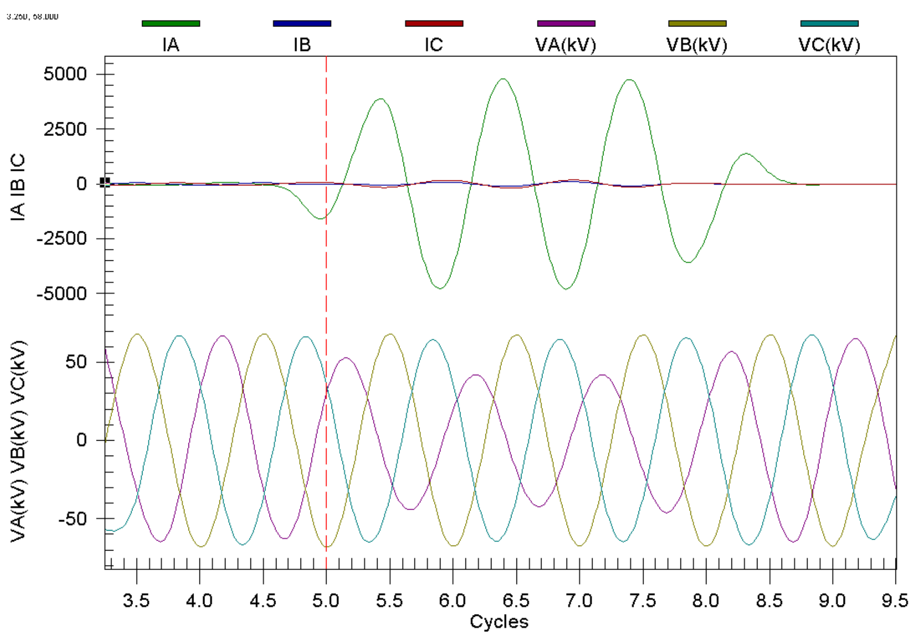

Figure 7-18: Relay Fault Record of Filtered Currents & Voltages for Wind Plant 4, Network Sub.

The six channels on Figure 7-19 are the filtered phase currents from the POI/collector substation and the voltage on the line side of the 115 kV breaker. Figure 7-20 contains two sets of channels. The first set is the magnitudes of the positive, negative, and zero sequence currents from the POI/collector substation's filtered phase currents and the second set is the magnitudes of the positive, negative, and zero sequence voltages from the filtered phase voltages on the line side of the 115 kV breaker at the POI/collector substation.

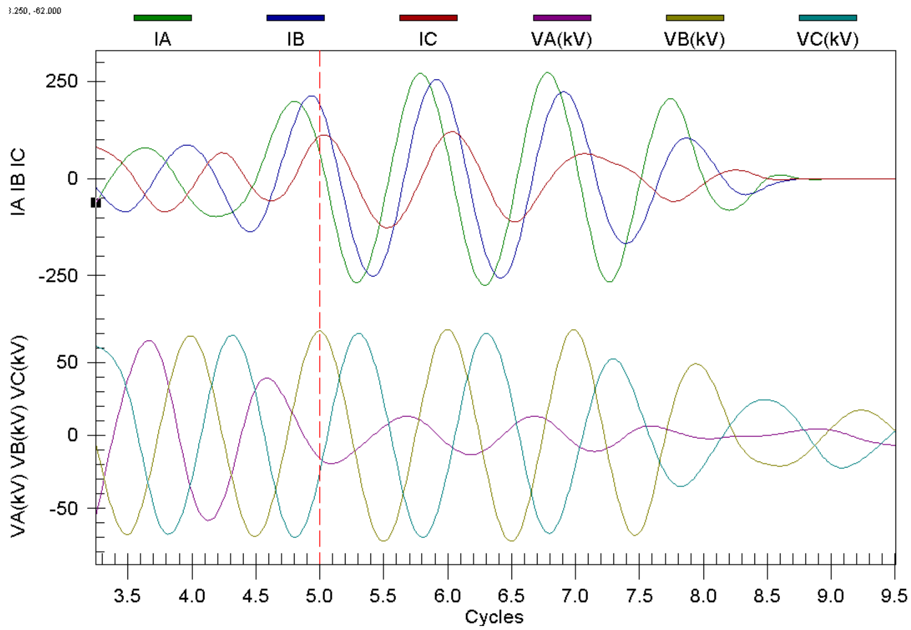

Figure 7-19: Relay Fault Record of Filtered Currents & Voltages for Wind Plant 4, POI/Collector Sub.

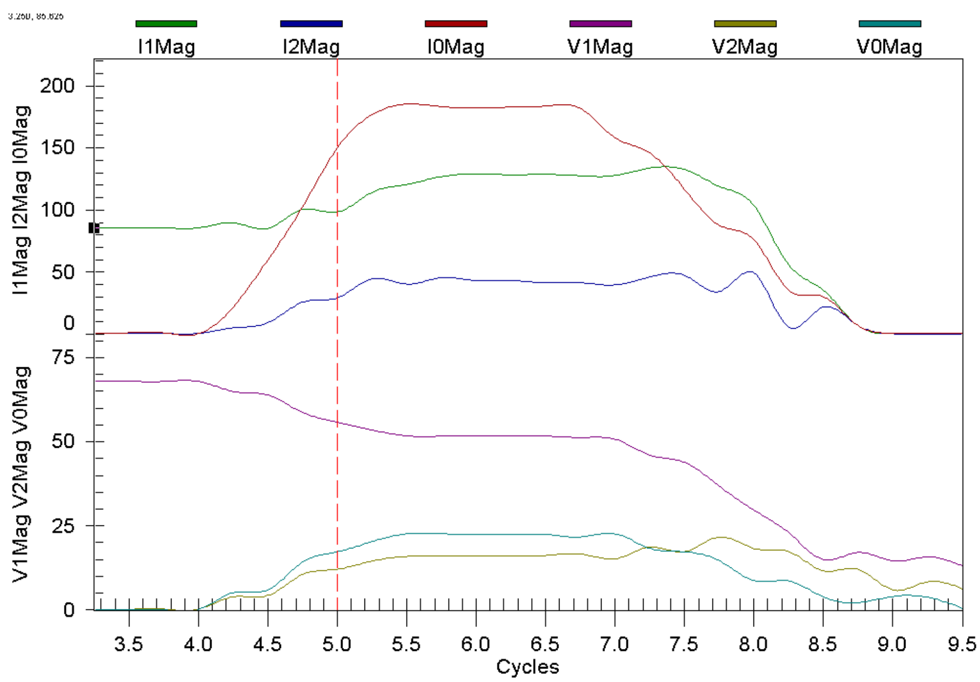

Figure 7-20: Relay Fault Record of Filtered Sequence Currents & Voltages for Wind Plant 4, POI/Collector.

Similar atypical rotating machine behavior can be observed in this case as was seen in the case with Wind Plant 1. The following measurements were taken from the sequence channels from the POI/collector substation at time 6.3 cycles in Figure 7-20 (approximately 1.9 cycles from the start of the fault):

V1 = 51,681 V	I1 = 129 A
V2 = 16,090 V	I2 = 43 A
V0 = 22,557 V	I0 = 182 A

Negative sequence source impedance from the collector substation is 374 Ω and the zero sequence source impedance is 123.9 Ω. The zero sequence impedance is the zero sequence source impedance of the 115 - 34.5 kV transformer with the effect of the grounding transformer on the 34.5 kV bus. Using the fault study model for the wind plant and assuming that the lines and transformers were correctly modeled the negative sequence generator impedance that will produce the 374 Ω combined source impedance is 0.33 per unit on the generators' base of 1.626 MVA.

As discussed above, positive sequence impedance of the generators at 1.9 cycles into the fault was calculated by the fault study program. The fault study program model was loaded to match the pre-fault power output of the wind plant. It was determined that the zero fault resistance produced negative sequence currents that matched the relay fault records. Using zero fault resistance in the single line to ground fault on the model with the load current the positive sequence impedance of the generators was adjusted to determine that with positive sequence impedance of 0.2 per unit on the generators' base will deliver the positive sequence current recorded by the relays when combined with the negative and zero sequence impedance already determined.

From the analysis of the fault records it was determined that at approximately 1.9 cycles into the fault, the Type III 1.626 MVA generators exhibited a performance to this fault as generators with the following per unit impedances: Z1 = 0.2 and Z2 = 0.33. Using these generator impedances in the fault study program the lowest phase to neutral voltage on the terminals of the generators during the fault ranged from a low of 0.51 per unit for the nearest generator to 0.52 per unit for the most remote.

7.5. Summary of the Results

The following is a summary of the results from the analysis of the data from the transmission line faults at four different wind plants at times approximately two cycles in the faults.

Wind plant 1, 66 – 1.5 MW Type III generators, Z1 = 0.4, Z2 = 0.36 per unit at 1.717 MVA with atypical rotating machine behavior with increasing positive sequence and decreasing negative sequence current.

Wind plant 2, 105 – 1.8 MW Type II generators, Z1 = 0.7, Z2 = 0.23 per unit at 2.0 MVA with typical rotating machine behavior.

Wind plant 3, 61 – 2.1 MW Type II generators, Z1 = 0.36, Z2 = 0.222 per unit at 2.283 MVA with typical rotating machine behavior.

Wind plant 4, 11- 1.5 MW Type III generators, Z1 = 0.2, Z2 = 0.33 per unit at 1.626 MVA with atypical rotating machine behavior with the positive sequence current increasing slightly during the fault.

8. Conclusion

This report examines several design and performance factors of WTGs connected to a power grid. The interconnection configuration, collector system design, generator type and selection of protection systems are described. The topics of this report provide engineers with an understanding of the consequences of the WTG plant design on short circuit contributions and the implications on the protection systems.

This report describes the performance of various types of WTGs during short circuit conditions. Fault records allowed measured fault currents to be compared to theoretical calculations by manufacturers and commercial software. The results indicate that the modeled and measured data for Type I and Type II generators are accurately compared. Of interest is the time it takes for the Type I generator short circuit current to reach a zero crossing due to the rate of decay of the DC component. The noteworthy effect of cable impedances on the Type II generators during a phase-to-ground fault within the wind plant collector system is graphically displayed.

Type III WTGs can be difficult to model accurately in commercial short-circuit programs, due to the variable fault current contribution during faults and operation of a crowbar function, which essentially shorts the rotor circuit of the generator. When the crowbar function is active, usually for severe close-in faults, the Type III generator effectively becomes an induction generator, similar to Type I or Type II generators. This mode of operation is only temporary but produces the maximum fault current immediately following fault inception and may be sufficient for determining equipment ratings and fault current withstand requirements.

When the crowbar is not engaged, the Type III generator behaves according to its design parameters, which may vary widely among manufacturers and even among different models from the same manufacturer. Depending on the severity of the fault, the controls may be configured to provide constant real power, constant reactive power, voltage boosting, current limiting, even intermittent application of the crowbar function, or some combination of these. Therefore developing a generic fault current model is not possible. Accurate modeling of the generator during controlled or non-crowbarred operation requires manufacturer's proprietary data and EMT simulation, which is generally impractical for performing short circuit analysis.

The report describes an alternative, iterative process that commercial short circuit software might implement that would not require proprietary data or EMT simulation, but which could provide an envelope of maximum and minimum fault currents. Typical ranges of fault currents immediately following fault inception and 3 cycles later are presented.

Type IV WTG will produce a STATCOM type of response to a system fault within the maximum current limitations of the device until the inverter controls detect and react to the fault condition. After the fault is detected the inverter controls adjust to a pre-set Fault Ride Through mode to meet the requirement of the power grid the plant is connected to.

The short circuit characteristics of Type V generators compare closely to other synchronous generators.

All five types of WTGs produce a short, 1–2 cycle, period of higher than normal currents for faults on the interconnected system when the generator terminal voltages are reduced. For the types I, II, and V these higher currents are the result of the inherent electrical behavior of the generator. For the Type III reduced terminal voltage may cause the rotor circuit of the generator to be modified temporarily so that the current out of the generator is similar to that from a type I generator for that initial period. And the inverter controls on the type IV WTGs will try to support the WTG terminal voltage to maintain the programmed power flow resulting in higher than normal current flow until the presence of the fault is detected and the inverter control mode is changed. This fault response period is critical for the operation of the protective relays on the interconnected system because it is during that same time period that the protective relays are determining whether to trip the circuit breakers or not.

Several protection system options exist for the wind plant interconnection, the collector system and the transmission system. The protection philosophies are discussed as they pertain to the system design and configuration.

Interconnection studies are required to assess the impact of the wind plant on the short circuit protection of the transmission system. The report provides guidance on the type of transmission and collector system data required to perform the studies.

Fault records of voltages and currents during transmission system faults on interconnected wind plants were collected and analyzed to better understand actual wind plant characteristics. Logs from the wind plant data systems were used to determine the operating conditions of the plant's individual WTGs (Type II or Type III) immediately prior to the fault. Using the detailed configuration data of the collection systems of the wind plants, the operational data, and the results from the fault records, the wind plant systems were modeled using a fault study program and compared to measured quantities. Generator sequence impedances were determined at critical times of interest. These impedances can then be applied to study the wind plant for other configurations.

This report provides a compilation of information on fault current contributions from wind plants. The type of WTG, the grid interconnection, the design of the collector system and the selection of the protection systems are brought together into this document.

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11. Abbreviations

ANSI	American National Standards Institute
BIL	Basic Insulation Level
CT	Current Transformer
DCB	Directional Comparison Blocking
DFG	Double-fed asynchronous Generator
DG	Distributed Generation
EHV	Extra High Voltage
EMT	Electro-magnetic Transient
EMTP	Electro-magnetic Transient Program
FERC	Federal Energy Regulatory Commission
HV	High Voltage
I0	Zero Sequence Current
I1	Positive Sequence Current
I2	Negative Sequence Current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
LVRT	Low Voltage Ride Through
MV	Medium Voltage
NEC	National Electric Code
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
PFCC	Power Factor Correction Capacitor
PLC	Power Line Carrier
PMSG	Permanent Magnet Synchronous Generator
POI	Point of Interconnection

POTT	Permissive Overreaching Transfer Trip
PSCAD	Power System Computer Aided Design
PU	Per Unit
RMS	Root Mean Square
SCIM	Squirrel Cage Induction Machine
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
TRV	Transient Recovery Voltage
WPP	Wind Power Plant
WTG	Wind Turbine Generator
XLPE	Cross-linked Polyethylene
V0	Zero Sequence Voltage
V1	Positive Sequence Voltage
V2	Negative Sequence Voltage
Z0	Zero Sequence Impedance
Z1	Positive Sequence Impedance
Z2	Negative Sequence Impedance