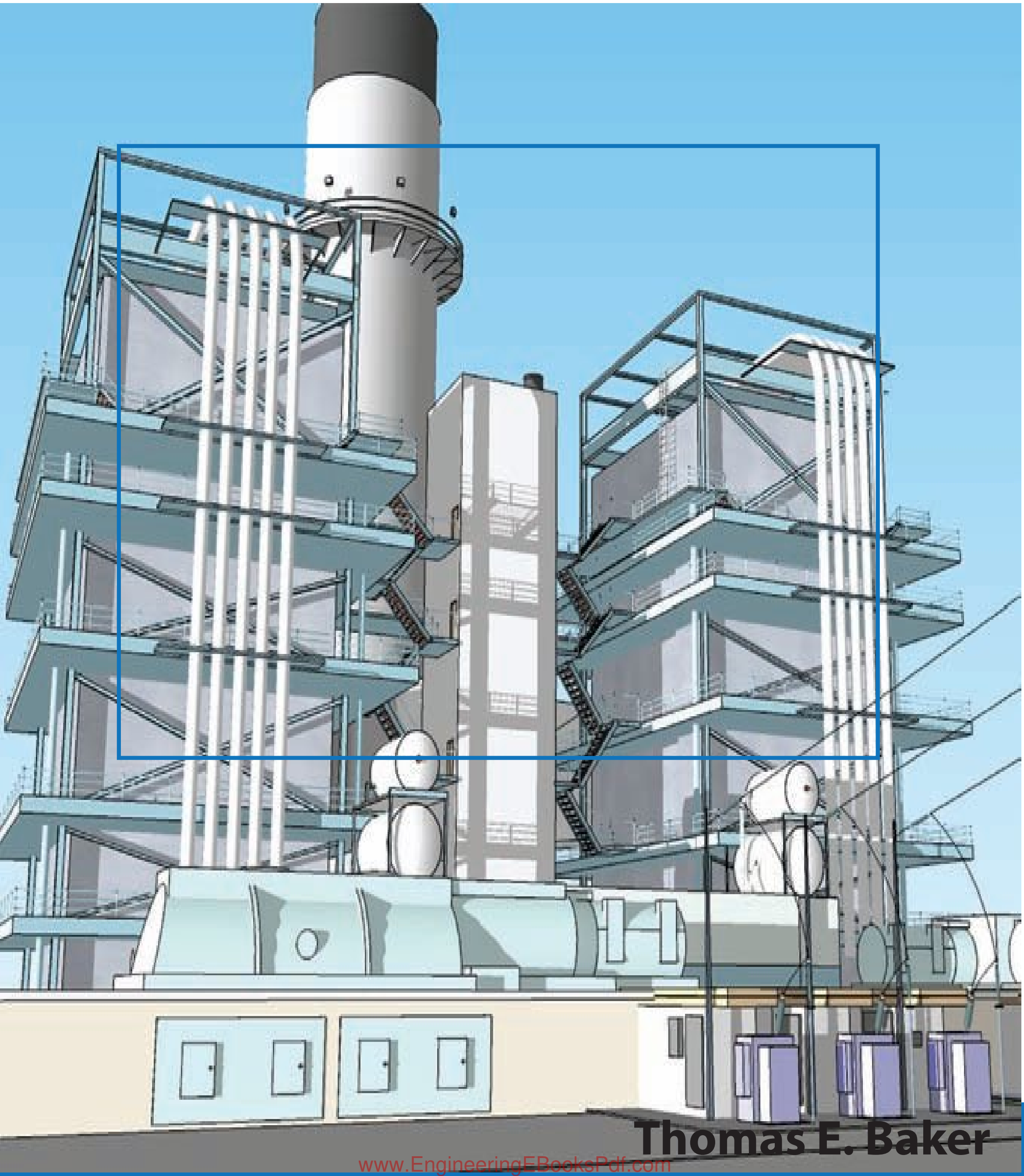
Electrical Calculations and Guidelines for Generating Stations and Industrial Plants



Thomas E. Baker

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Preface

The objective of this book is to simplify the theory and calculations that electrical engineers typically need to understand in order to support operations, maintenance, and betterment projects for generating stations and industrial facilities.

The book is organized into seven chapters: "The Basics," "Electrical Studies," "Auxiliary System Protection," "Generator Protection," "Electrical Apparatus Calculations," "Electrical Operating Guidelines," and "Electrical Maintenance Guidelines."

Chapter 1, "The Basics," provides a cursory review or refresher of basic electrical theory. It also provides additional insights into electrical theory that typically are not presented and sets the conventions that will be utilized throughout the book. Therefore, even the more experienced electrical engineers are encouraged to start with the first chapter.

The "Electrical Studies" chapter (Chapter 2) discusses the conversions, data gathering, and calculation procedures for voltage studies, power transfer, and short circuit analysis. In the interest of simplicity, when a calculation does not involve transformation, a three-phase version of Ohm's Law is applied to simplify the procedure. When transformers are involved in the calculation (short circuit studies), the per-unit system is utilized.

Chapter 3, "Auxiliary System Protection," covers switchgear overcurrent coordination, high impedance ground detection schemes, transformer protection, and residual voltage bus transfer circuits. Detailed background information is provided on the time coordination of overcurrent relays and on the benefits and electrical phenomena associated with the application of high impedance (resistance) ground detection schemes.

"Generator Protection" (Chapter 4) explains the gathering of data needed to set the various protection functions, the calculation procedures for actually setting the elements, and the math associated with the various types of impedance elements. It also provides substantial details on the need for the protection functions and typical generator and turbine withstands for the associated abnormal operating conditions.

Chapter 5, "Electrical Apparatus Calculations," discusses practical apparatus calculations that were not included in the preceding chapters. Calculation procedures are provided for various aspects of buses, cable, circuit breakers, current transformers, generators, meters, motors, and transformers.

The final two chapters present suggested electrical operating and maintenance guidelines for generating station and industrial facilities. In reality, guidelines are moving targets that require periodic revision to reflect site-specific experience and conditions, industry experience, manufacturers' recommendations, and the ever-changing regulatory requirements.

Acknowledgments

Special thanks to my wife Janet, who not only put up with the many hours it takes to complete an engineering book but encouraged me to see it through to completion.

My son John Baker, B.S. Computer Science, created the graphics and developed the code for the EE Helper Power Engineering software program. The software graphics are utilized throughout the book, and his assistance was extremely valuable in the development of this book.

I also want to thank my good friend and associate Dr. Isidor Kerszenbaum, Institute of Electrical and Electronics Engineers (IEEE) Fellow, and author and coauthor of the last three IEEE Press books on generators, for not only taking the time to review the book but for also providing important suggestions that have been incorporated in the text to improve the presentation of the material.

Particular thanks to Donald Reimert, author of an advanced book on generator and motor protection titled *Protective Relaying for Power Generation Systems* (CRC Press, 2006), for being kind enough to review the book even though we have not personally met and for providing comments on the content of the book.

Finally, I want to thank Phillip Wheeler, former Southern California Edison (SCE) supervising electrical apparatus engineer, who is active in the regional IEEE Power Engineering Society/Industrial Applications Society (PES/IAS) leadership, forensic consulting, and expert witness testimony, for his comments on the book.

About the Author

Thomas E. Baker was working for Southern California Edison (SCE) as a protective relay technician performing new construction and overhaul testing of large generating station electrical systems and associated high voltage switchyards when he was inducted into the Marine Corps. Following release from active duty, he returned to the technician position and took advantage of the GI educational bill, eventually completing a master's degree in electrical power engineering and management.

Following graduation, Baker held various electrical engineering positions involving metering, protection, distribution, and apparatus, and for the last 15 years of his career with SCE, he was responsible for the electrical engineering support of 12 fossil fueled generating stations. A specific generating station location usually does not have many significant electrical events, but overseeing 12 stations exposed him to many major operating and maintenance errors, short circuits, and electrical apparatus failures.

Following an early retirement from SCE due to deregulation in California, Baker worked as a consultant in the United States and overseas. He found it a little unsettling to be sent halfway around the world and show up with only a calculator and no reference material. His son John was completing a computer science degree during that time, and they teamed up to design a software program (132 calculations) that would facilitate Baker's consulting work. Each software calculation has an associated graphic that illustrates the circuitry, formulas, and references; the software graphics are utilized throughout this book. Later, Baker realized that the graphics could also be used for electrical power engineering training, and as of this writing, he has presented 9 hotel and 20 on-site 4-day seminars that are approved by the IEEE for continuing education units.

Considering both his SCE experience and his consulting work, Baker has completed protection reviews on approximately 30,000 megawatts of gas, oil, coal, and nuclear generation. Consequently, he is well aware of common protective relay oversights that can impact station productivity through the lack of coordination, nuisance tripping, and inadequate protection of electrical apparatus.

1

The Basics

This chapter addresses the basic theories and conventions associated with three-phase alternating current (AC) electrical power systems. Some of the theories contained in the chapter and throughout the book are not commonly presented and the content should enhance the reader's understanding of three-phase power. Although the main focus of this book is generation, theory is theory, and much of the material presented can be directly applied to the transmission and distribution of electrical power as well.

1.1 Three-Phase History

In 1888, Nikola Tesla (Serbian) delivered a lecture on the advantages of polyphase AC power. The first transmission of three-phase power occurred in Germany during 1891 at 25,000 volts or 25 kilovolts (kV). During the early 1900s, three-phase high voltage transmission became rather commonplace in the more developed countries. Today in the United States, 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, and 765 kV are commonly used in bulk power electrical systems to convey power several hundred miles in order to link large areas and multiple states together into a single network.

1.2 Three-Phase System Advantages

Three-phase systems provide the following advantages:

- Three-phase power creates a rotating magnetic field in the stator windings of large induction and synchronous motors. This rotating magnetic field significantly simplifies the design and applies the required rotational force to the rotor and in turn to the driven equipment.
- A single-phase system requires two conductors: one to deliver the current to the load and the other to return the current to the source, thereby completing the circuit. By simply adding one more conductor, significant economies can be realized in the amount of

power transfer capability. If the three phase-to-phase voltages are equal to the single-phase system voltage, the amount of power transferred can be increased by a factor of 1.732 and the line watt losses only increase by a factor of 1.5. The incremental cost to add one more conductor is small compared to the cost of the towers or poles and the real estate for right-of-way purposes.

1.3 Theory

Before the book delves too deeply into three-phase systems, a cursory review of basic electrical theory concepts and conventions that also apply to three-phase power may be beneficial. As you will see, magnetism and the development of voltages and currents are particularly complex, especially when one looks at the Bohr model of the atom and the relationships of the various components. Three-phase motors and generators on the surface appear to be relatively simple machines, but in actuality, the electrical relationships are extremely complex and involve many three-dimensional magnetic and electrical parameters that present a spatial challenge.

Developing a simple understanding of magnetic and electrical parameters by relating them to the Bohr model of the atom is difficult because the vast majority of electrical engineering reference and textbooks only address the mathematical expressions and do not explain the mechanisms at the atomic level. Even the most basic questions are not typically addressed: Why is a changing flux required to induce a voltage? How does AC current appear to flow at or near the speed of light? What causes hysteresis magnetic loss? Assuming that the Bohr model and known relationships are approximately correct and by researching various papers on the subject, one can deduce simple concepts or explanations that may help the reader grasp and retain the theory. One must keep in mind however, that no one has ever seen an atom, proton, or electron and that a proton is approximately 1836 times larger in mass than an electron.

1.4 Magnetism

There are two electrical components that seem to impact electrical circuits at any location: magnetic flux and capacitance. No material is able to prevent magnetic lines of force or flux from flowing. Consequently, a donut-type current transformer can be applied around shielded cable and function properly; any eddy current effects in the shield will be cancelled out by the circular nature of the current transformer core and cable shield. However, if the shield is grounded at both ends, longitudinal current flow in the shield will cause an error in the current measurement. Magnetic flux shielding can be provided by enclosing the area of interest inside a magnetic material that will attract the flux away from the interior. A magnetic material is one that has low reluctivity or reluctance and facilitates or attracts magnetic flux. Another method is to allow eddy currents to flow in a conducting shield (often used in generators and transformers), which produces an opposing flux that reduces the original flux.

Many of the magnetic concepts and mathematical expressions were developed during the first half of the 19th century. Some of the more notable pioneers during that period were Michael Faraday (English) for induced voltages; André-Marie Ampère, Jean-Baptiste Biot, and Victor Savart (French) for induced forces; Joseph Henry (American) for self inductance; and Heinrich Lenz (Estonian) for opposing effects. During the second half of the 19th century, Hendrik Lorentz (Dutch) improved the expression for opposing force calculations.

The following list presents some of the basic elements or relationships in magnetic theory:

- Reluctivity (nu or ν)
  - = .313 for nonmagnetic material
  - = .007 to .00009 for magnetic material
- Reluctance ($\Re$) = ν L/A L = magnetic length (inches) and A = cross-sectional area (inches)
- Permeability (mu or μ) = $1/\nu$ = B/H
- Ampere turns (IT) or mmf (magnetomotive force)
- Flux (φ) = IT/$\Re$
- Flux density per square inch (B) = φ/A
- Voltage (E) = 10^8 flux lines per second per volt = $\Delta\varphi/(S10^8)$ S = seconds
- E = $\Delta\varphi/\Delta T$ or BLV L = active length of conductor and V = velocity
- Magnetic force required to overcome length (H) = IT/L
- Lenz's Law: induced currents will try to cancel originating cause
- Force (F) in pounds = $(8.85\ \mathrm{BIL})/10^8$ I = amps L = active length of conductor (inches)

Figure 1.1 shows Fleming's right-hand rule for generators in vector form. As you can see, the original flux (B) is shown as a reference at 0 degrees, the initiating motion (M) or velocity at 90 degrees (cross section of a conductor moving upward and crossing the flux), current (I) flowing three-dimensionally into the paper or figure at the point of origin (closed

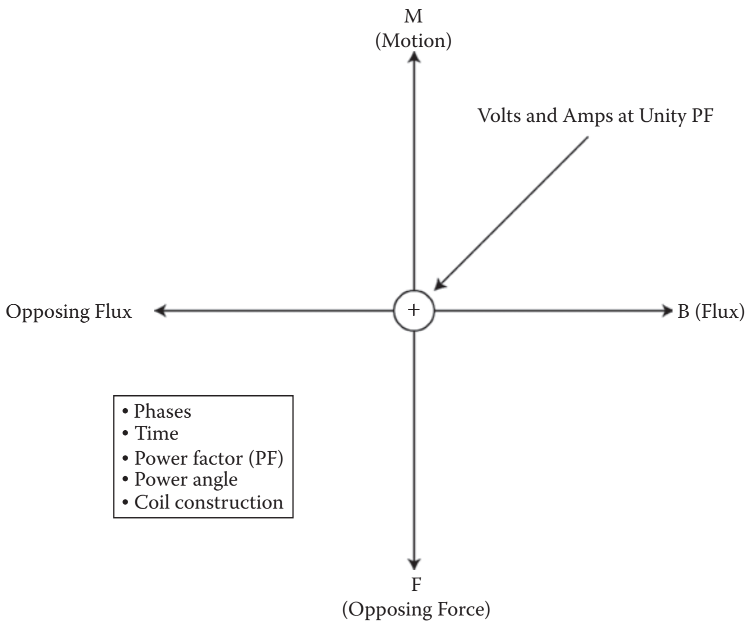


FIGURE 1.1
Magnetic Phasors

resistive circuit), an opposing force (F) from current flow at 270 degrees, and an opposing flux from current flow at 180 degrees.

The lower left area of the figure denotes some of the conditions that will impact the placement of a particular phasor, that is, time, phase, power angle, power factor, and coil construction. Coils can change the position of current induced magnetic flux. In a single conductor, the flux produced by current flow will occupy a position that is 90 degrees from the current flow in a circular fashion around the conductor. However, in a coil, the circular flux from one turn is in opposition to the circular flux of an adjacent turn. Consequently, the flux flows in the interior of the coil and exits at the ends to enclose the coil in an inner and outer flux. However, it still links each coil turn by 90 degrees as each turn is mechanically or physically displaced by 90 degrees.

Figure 1.2 shows the Bohr Model of a simple hydrogen atom, which consists of one positively charged proton and one negatively charged electron. The model was introduced by Niels Bohr (Danish) in 1913. Although the basic hydrogen atom is not equipped with a neutron, one is shown in the figure for clarity since other elements have neutrons. The mass of neutrons are thought to provide a binding force for atoms that contain more than one proton in their nucleus (like charges repel).

If a strong enough magnetic flux is applied, the proton will align with the flux and orientate or flip the atom accordingly. This realignment has an

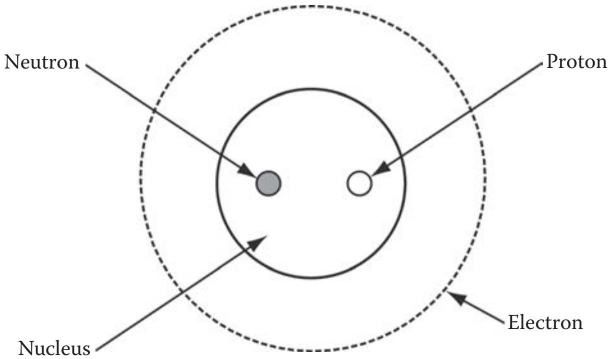


FIGURE 1.2
Bohr Model of the Atom

energy requirement before it can occur, and atoms in magnetic materials will align at much lower energy thresholds. The amount of energy required before the atom flips causes a lag in alignment and hysteresis loss in the core iron of AC transformers, generators, and motors. This loss can be reduced by adding silicon to the steel to reduce the flip energy. Different elements can also be identified by evaluating the reset time or the time for the atoms to return to their original position after the magnetic field is removed. In a permanent magnet (hard material), many of the atoms do not reset and the material maintains a residual magnetism.

If enough atoms align, which readily happens in magnetic materials (iron, steel, nickel, and cobalt), a useable magnetic flux will be generated. This magnetic flux is generated at 90 degrees from the charged spinning electron and radiates outward. In relation to Figure 1.2, it would either be in a direction toward the reader or into the paper depending on the relative polarities.

1.5 Voltage and Current

In 1800, Alessandro Volta (Italian) invented the electric battery. The electrical unit (symbol E or V) for electrical voltage or pressure is named after him. One volt will produce a flow of one ampere in a closed circuit that has one ohm. In 1827, George Ohm (Bavarian) developed the expression for Ohm's Law, which describes the mathematical relationship of volts, amps, and resistance, or ohms, in a closed circuit. The current can be determined by simply dividing the voltage by the resistance, or impedance, in an AC circuit.

Photons are packets of quantum of energy that are thought to be without mass and consist of self-propagating electrical and magnetic waves that travel at the speed of light, or 186,000 miles per second, regardless of frequency. This electromagnetic propagation includes low frequencies in the communication range, infrared, the visible spectrum, ultraviolet, x-rays, and gamma and cosmic rays at the high end. In the visible spectrum (light), the different frequencies produce different colors. In 1900, Max Planck (German) developed a constant h for photon energy. Basically, he proposed that the energy in a photon was a function of the frequency; the higher the frequency, the higher the energy content. An orbiting electron's potential energy increases as the radius or distance from the nucleus increases. A photon striking an atom can increase the electron orbit radius, imparting an increase in potential energy. A fall in the orbit level is thought to initiate an electromagnetic propagation or photon as the electron gives up its potential energy and settles into the original lower or closer orbit. The distance of the fall from one orbit level to another determines the frequency and wavelength of the propagation.

The generation of alternating voltage requires a continual changing magnetic flux. One explanation at the atomic level is that the magnetic flux sweeps the electron orbit causing it to pick up potential energy as it becomes more elliptical and less symmetrical. As the neighboring electron forces drive the orbit back to its normal position, there would be a loss of potential energy. This loss of electron potential energy may represent the voltage that is measured in an AC circuit.

If the circuit is complete or closed, a current will flow. Current flow or amperes (amps) are named in honor of André-Marie Ampère and are denoted by the symbol A or I. Current flow involving AC has a different mechanism than DC. Conventional theory postulates that current flow and electron flow are the same. At the atomic level, this theory does not seem possible. Practically speaking, AC current in a conductor appears to flow at or near the speed of light. Electrons have some mass and consequently should not be capable of traveling at the speed of electromagnetic waves or photons that do not possess mass. Also, the orbiting speed of electrons is much slower than the speed of light, and electrons would need to accelerate significantly to attain the speed of AC current flow in a conductor. Electron orbits that are closer to the nucleus require the fastest orbit speed (1/100 the speed of light) because they have the strongest attraction to protons. Electrons orbit to acquire centripetal force, which prevents them from being sucked into the nucleus by the proton attraction. If they go too fast, they will be flung free from the atom. The loss of potential energy as the orbit returns to its more original symmetrical position probably produces a weak photon-like wave.

Basically, the same mechanism that launches a photon may be involved with AC current flow. Although this very low frequency electromagnetic wave would not have enough energy to propagate outside of the conductor, it may have enough energy to flow if there is a complete or closed circuit, and may account for the known effects of AC current flow in a conductor. Some sources indicate that the electromagnetic waves cause orbiting electrons to oscillate or vibrate as they travel through the conductor, which in turn creates the watt loss heating effect. This watt loss would prevent continued self-propagation since the energy is dissipated as heat. The wave may also have more of a tendency to flow on the outside surfaces (skin effect) where the electron density is lower. Although this and the prior couple of paragraphs are speculative in nature, they do seem to fit the Bohr model of the atom, seem to be consistent with the way basic photon theory is presented in physic courses, and provides the nonphysicist or layperson with some insight on AC electricity and atomic behavior.

Alternating voltages and currents from generators and in three-phase power systems are sinusoidal or in the form of sine waves. The root mean square (RMS) values replicate the voltage and currents used to calculate watts in a direct current (DC) circuit. The RMS values for both currents and voltages can be determined by simply multiplying the peak or maximum values by the sine of a 45-degree angle, or 0.7071. Unless specified differently, the RMS values will be used throughout the book for AC voltage magnitudes and for both peak and nonpeak currents.

1.6 Resistance

Electrical resistance impedes the flow of current in conductors and insulators. Resistance is measured in ohms in honor of George Ohm (symbol R or Ω) and is affected by the temperature of the conductor or insulator. The resistance of a conductive material increases with an increase in temperature. This phenomenon is thought to be associated with the more chaotic motions of atoms at higher temperatures. With insulating materials, the opposite occurs; the resistance decreases with an increase in temperature that may be associated with less tightly bound orbiting electrons. For both conductors and insulators, resistance values are normally specified at specific temperatures and need to be corrected for temperature differences, that is, buses at 80°C, insulated cable at 75°C, overhead aluminum conductor steel reinforced (ACSR) at 50°C, and minimum megohms for insulation systems at 40°C.

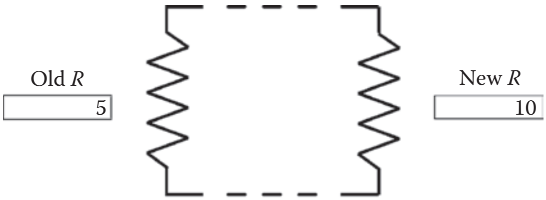
The ohmic or resistance values of conductors with ac flowing is higher than when DC flows. An AC resistance value is used that is congruent with the amps squared R heating (I^2R) from current flow. According to conventional theory, the main difference is caused by skin effect in AC, where much of the current wants to flow near the outside surfaces instead of taking advantage of all of the conducting material. There can also be additional effects from conduits, shielding, and proximity to other conductors. One likely contribution is that the subtractive magnetic flux from current flowing in other phases or neutral conductors have the most impact near the surface areas where they are stronger and lower the surface impedance path accordingly. Unless specified differently, resistance values mentioned in this book will be based on AC resistance and not DC resistance. The AC resistance values for conductors are readily available in manufacturers' data, the Insitute of Electrical and Electronics Engineers (IEEE) Standard 141, and other reference books.

1.7 Inductance

The inductance of conductors and coils impedes current flow in an AC circuit. It is caused by a self-magnetic flux that induces opposition voltages in conductors when current flows. The opposition voltage also tries to resist any change in current flow. As the source sine wave approaches zero, the opposing voltage will try to prevent the new direction of current flow and force the current to lag the source voltage. The unit for inductance, the henry (symbol L), is named after Joseph Henry. When a rate of change of current of 1 amp per second results in an induced voltage of 1 volt, the inductance of the circuit is said to be 1 henry. When current flows and returns in conductors in close proximity, the magnetic flux from the return conductor subtracts from the source conductor flux, which reduces the overall inductance of the conductors. If the wires are spread apart, the inductance will increase as the subtractive flux weakens. If the wires are wound in a coil, the inductance will increase dramatically, and if wound around iron, much more dramatically.

1.8 Capacitance

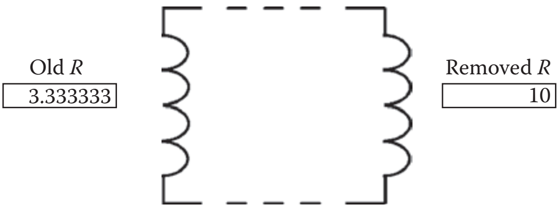
Capacitance can also impede current flow in an AC circuit. Capacitors store voltage or potential energy, perhaps by moving electrons to a higher orbit, thereby increasing their potential energy. The stored voltage tries to maintain and/or increase the circuit voltage. As the source sine wave approaches zero, the stored voltage pushes current in the new direction in advance of the source voltage causing the current to lead the source voltage. The unit for capacitance, the farad (symbol C), is named in honor of Michael Faraday. One farad can store one coulomb (amp-second) of charge at one volt. The coulomb (symbol Q) is named in honor of Charles-Augustin de Coulomb (French) for his work in electrostatic forces in the 1700s. Capacitance is a function of a dielectric constant times the conductive plate areas divided by the distance between plates. The dielectric (insulating materials or air) could be the insulation on wires or cable, and the plates could be composed of the conductor on one side and another conductor or earth ground for the other



$$Total\ R = \left(\frac{1}{\frac{1}{Old} + \frac{1}{New}}\right) \quad \boxed{3.333333}$$

Notes:
New *R* is the resistance value of a new parallel leg that is connected to a pure resistive circuit.

FIGURE 1.3
Parallel Resistors



$$Total\ R = \left(\frac{1}{\frac{1}{Old} - \frac{1}{Removed}}\right) \quad \boxed{5.0}$$

Notes:
Removed *R* is the resistance value of a parallel leg that is eliminated from a pure resistive circuit.

FIGURE 1.4
Removing Parallel Resistance

plate. Consequently, stray capacitance is everywhere and can have an impact on every AC electrical circuit.

1.9 Circuits

Series circuits, as the name implies, denote a single source with devices connected in a consecutive manner where the same current flows in all connected devices. With the exception of capacitors (farads are treated as if they were connected in parallel since a series connection reduces the total farads), the total value for like devices connected in series is simply the mathematical sum of each, that is, resistors, inductors, reactance, and impedance, if the angles are the same. For example, three 2.0 ohm resistors connected in series would have a total ohmic value of 6.0.

Parallel circuits, as the name also implies, denote a single source with two or more legs, each having the same voltage, but an independent current. Each leg internally can be handled as a series circuit, but the total seen by the source would be the reciprocal of the sum of the reciprocals for simple legs using the same or like components, that is, resistors, inductors, reactance, and impedance (if the angles are the same). Again, capacitors are an exception because the total farads of each parallel leg would simply be added together. Figures 1.3 and 1.4 illustrate the procedures for adding and removing parallel resistors. Graphic modules developed for the EE Helper Power Engineering Software program are used in these figures and throughout the book.

1.10 Time Constants

Figure 1.5 through Figure 1.8 display time constant calculations and associated charge and discharge times for capacitors and inductors. Capacitors and inductors cannot charge or discharge instantaneously if resistance is in the circuit. The resistance limits the amount of current that can flow at a given time. At minimum, some resistance will always be present in the source and in the conductors that feed the capacitance or inductance. Although the

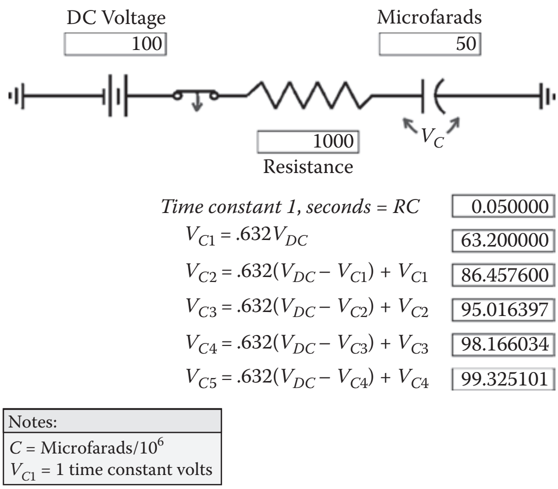
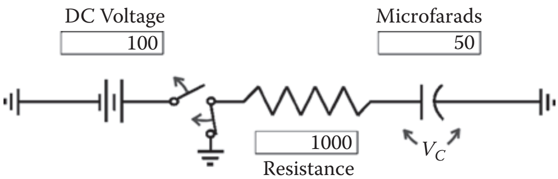


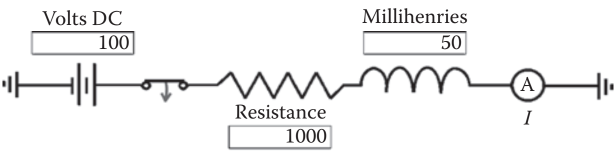
FIGURE 1.5
Charging Resistor-Capacitor (RC)



Time constant 1, seconds = RC	0.050000
$V_{C1} = (1 - .632)\ V_{DC}$	36.800000
$V_{C2} = (1 - .632)\ V_{C1}$	13.542400
$V_{C3} = (1 - .632)\ V_{C2}$	4.983603
$V_{C4} = (1 - .632)\ V_{C3}$	1.833966
$V_{C5} = (1 - .632)\ V_{C4}$	0.674899

Notes:
C = Microfarads/10^6
V_{C1} = 1 time constant volts

FIGURE 1.6
Discharging Resistor-Capacitor (RC)



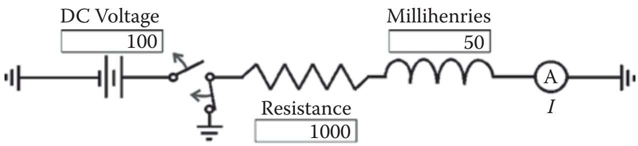
Time constant 1, seconds = L/R	0.000050
Maximum amps $I_m = V_{DC}/R$	0.100000
$I_1 = .632\ I_m$	0.063200
$I_2 = .632\ (I_m - I_1) + I_1$	0.086458
$I_3 = .632\ (I_m - I_2) + I_2$	0.095016
$I_4 = .632\ (I_m - I_3) + I_3$	0.098166
$I_5 = .632\ (I_m - I_4) + I_4$	0.099325

Notes:
L = Millihenries/10^3
I_1 = 1 time constant amps

FIGURE 1.7
Charging Resistor-Inductor (RL)

figures show a DC voltage, resistance, and current, the same phenomenon occurs as the sine wave goes through peaks, valleys, and reversals in an AC current.

Figure 1.5 shows a resistor-capacitor (RC) charging circuit consisting of a 100 volt DC source and a 1000 ohm resistor connected in series with a 50 microfarad capacitor. One time constant (in seconds) is the ohmic value of the resistor times the capacitance value in farads. It takes approximately



Time constant 1, seconds = L/R	0.000050
Maximum amps $I_m = V_{DC}/R$	0.100000
$I_1 = (1 - .632)\ I_m$	0.036800
$I_2 = (1 - .632)\ I_1$	0.013542
$I_3 = (1 - .632)\ I_2$	0.004984
$I_4 = (1 - .632)\ I_3$	0.001834
$I_5 = (1 - .632)\ I_4$	0.000675

Notes:
L = Millihenries/10^3
I_1 = 1 time constant amps

FIGURE 1.8
Discharging Resistor-Inductor (RL)

5 time constants to fully charge a discharged capacitor. As you can see, the capacitor has a 63.2% charge in 1 time constant and is almost fully charged in 5 time constants. The discharging circuit is shown in Figure 1.6. The time constant is the same, and the capacitor will be discharged 63.2% in 1 time constant and, practically speaking, fully discharged in 5 time constants.

Figure 1.7 presents a charging circuit for inductance consisting of a 100 volt DC source feeding a 1000 ohm resistor connected in series with a 50 millihenry inductance. The time constant in seconds in this case is inductance/resistance (L/R), and the measurement is current. As you can see, the current attains 63.2% of the maximum value in 1 time constant and reaches almost 100% in 5 time constants.

Figure 1.8 exhibits the discharging parameters for the same circuit. The time constant is the same, and the current is reduced by 63.2% in 1 time constant and almost to zero in 5 time constants. As you will see in ensuing text and chapters, this L/R relationship is applied in power engineering as an X/R ratio to determine current decrements, power factor, and short circuit angles.

1.11 Reactance

To solve electrical problems and perform studies, the capacitive and inductive parameters that also impede the flow of a changing alternating current need to be converted to a base that is similar to resistive ohms. Figure 1.9 illustrates the procedure for converting farads to a similar ohmic value denoted

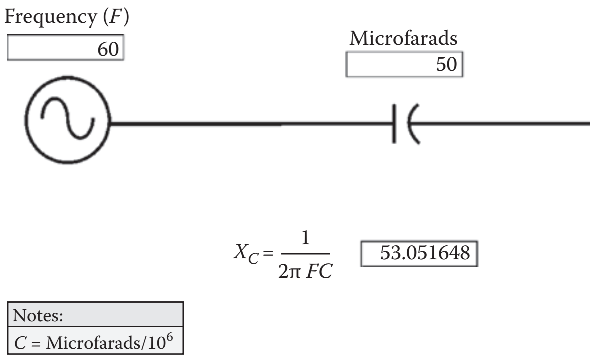


FIGURE 1.9
Capacitive Reactance

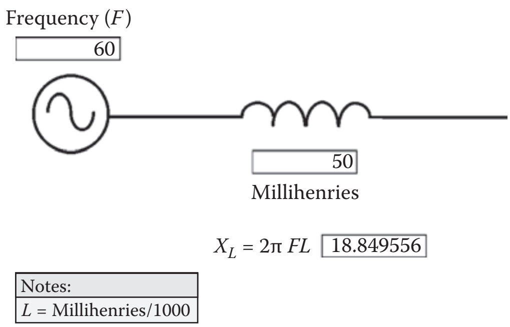


FIGURE 1.10
Inductive Reactance

by the symbol X_C. Figure 1.10 shows a process for converting henries into X_L, which also has a similarity to resistive ohms. The capacitive and inductive ohms are called *capacitive reactance* and *inductive reactance*, respectively.

1.12 Series Impedance

Figure 1.11 through Figure 1.18 illustrate procedures for handling series impedance and their vector relationships. In this case, impedance represents the vector sum of resistive, inductive, and capacitive ohms. As mentioned earlier, capacitance causes the current to lead, inductance causes it to lag, and any resistive component will be in phase with the reference. Current is used as a reference in series circuits, because it is the same in all parts of the circuit, and the voltage drops are the vector quantities.

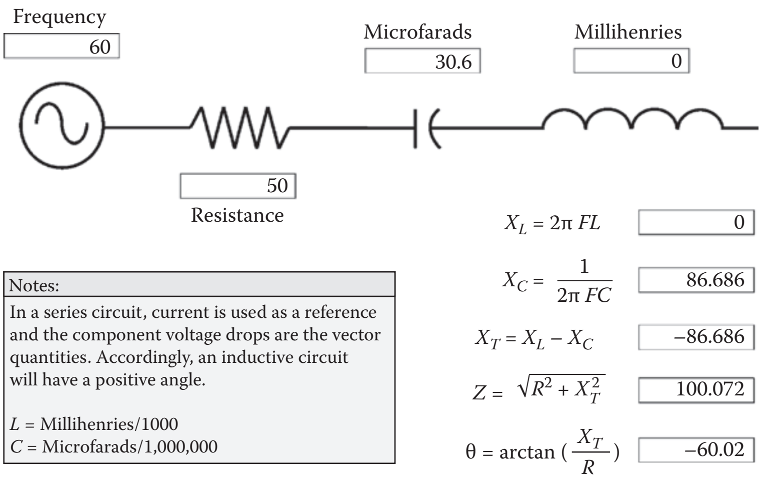


FIGURE 1.11
Series Capacitive Impedance

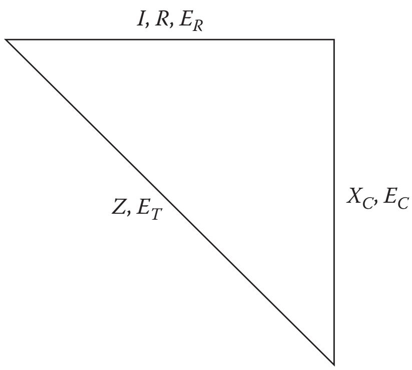


FIGURE 1.12
Series Capacitive Right Triangle

Figure 1.11 deals with determining the impedance of a circuit that has resistance in series with capacitance, and Figure 1.12 shows the vector relationships. As you can see, it is a right triangle relationship, with the triangle intruding into the fourth quadrant. Because vector rotation is counterclockwise and current is the reference, I, R, and E_R (resistive voltage drop) are shown at 0 degrees, X_C and E_C (capacitive voltage drop) at 270 degrees, and the hypotenuse represents the total impedance Z and total circuit voltage E_T at an angle of 300 degrees. The total current that flows is E_T/Z.

Figure 1.13 covers the same procedure for determining the impedance of a circuit that has resistance in series with inductance, and Figure 1.14 shows

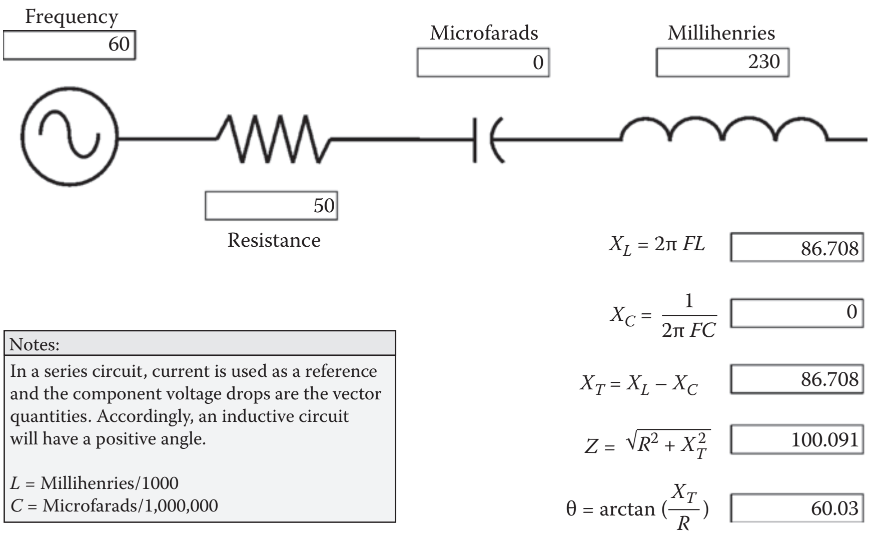


FIGURE 1.13
Series Inductive Impedance

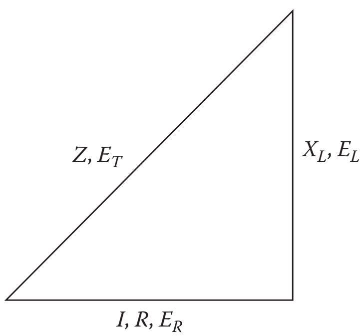


FIGURE 1.14
Series Inductive Right Triangle

the vector relationships. As you can see, it is also a right triangle relationship, with the triangle intruding into the first quadrant. In this case, I, R, and E_R are shown at 0 degrees, X_L and E_L (inductive voltage drop) at 90 degrees, and the hypotenuse represents the total impedance Z and total circuit voltage E_T at an angle of 60 degrees. This particular right triangle representation will be used throughout the book, as most power circuits are series circuit representations that are inductive in nature. Even transmission lines that are part of a network are represented in a series fashion when looking at the impedance components of the line itself.

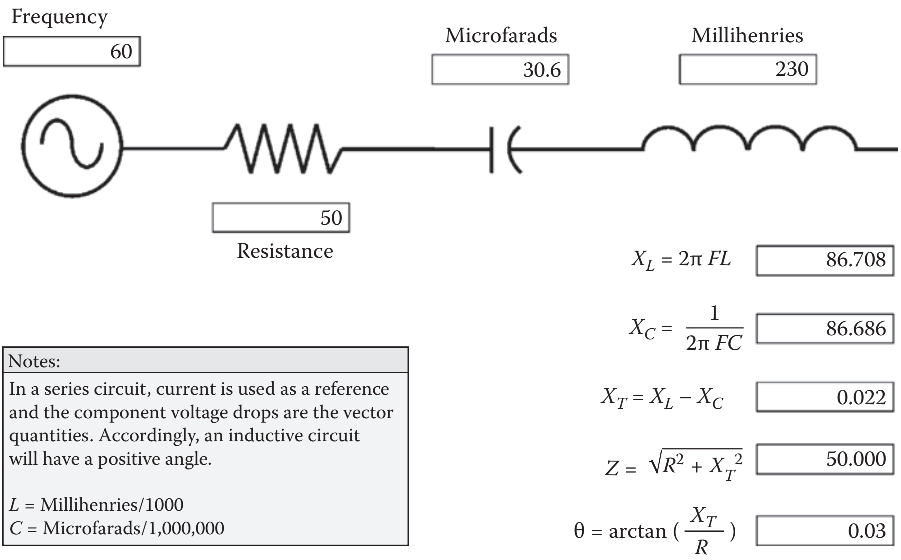


FIGURE 1.15
Series Resonant Impedance

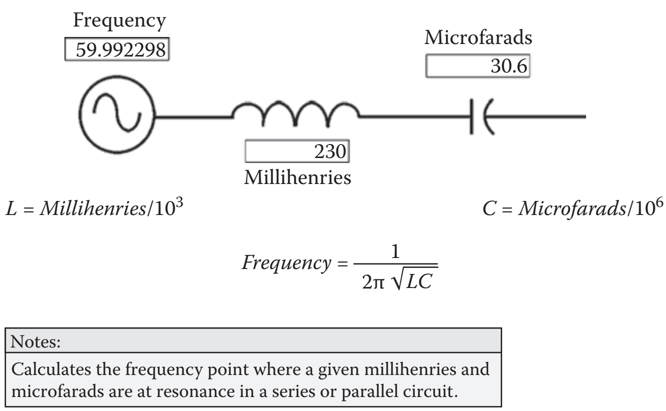
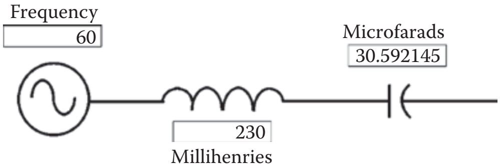


FIGURE 1.16
Resonant Frequency

A series circuit with all three components—resistance, capacitance and inductance—is illustrated in Figure 1.15. As you can see, the capacitive reactance is equal to the inductive reactance, and the current is limited by the resistive component only. This is referred to as *resonance.* If the circuit resistance is low enough, very high or short circuit currents can flow. Figure 1.16 displays a procedure for calculating resonant frequencies, Figure 1.17 shows how to calculate the capacitive portion at a given frequency, and Figure 1.18, the inductive portion.



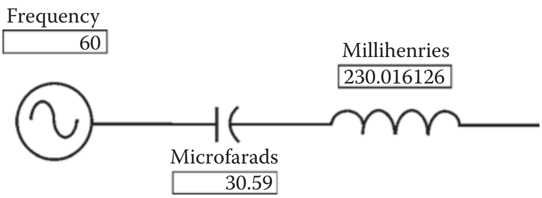
$$Farads = \frac{1}{(2\pi)^2 F^2 L}$$

$$Microfarads = 10^6\, Farads \qquad L = Millihenries/10^3$$

Notes:
Calculates the microfarads needed to resonate with a given millihenries and frequency in a series or parallel circuit.

FIGURE 1.17
Capacitive Resonance

Inductive Resonance



$$C = Microfarads/10^6$$

$$Henries = \frac{1}{(2\pi)^2 F^2 C}$$

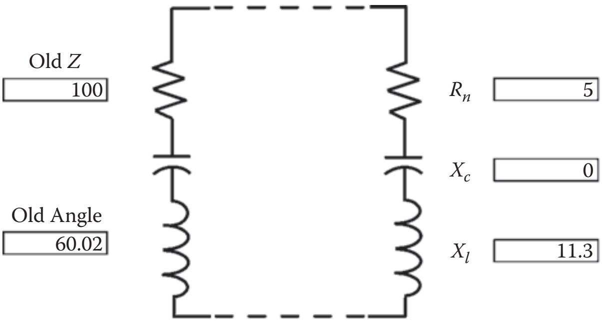
$$Millihenries = 10^3\, Henries$$

Notes:
Calculates the millihenries needed to resonate with a given microfarads and frequency in a series or parallel circuit.

FIGURE 1.18
Inductive Resonance

1.13 Parallel Impedance

Figure 1.19 presents the procedure for calculating parallel impedance. In parallel circuits, the voltage is the same in each leg, and each leg current is independent of the other legs; consequently, the voltage is the reference and the leg currents are the vector quantities. The old impedance represents the capacitive impedance of Figure 1.11, except the polarity of the angle is shown



o = old
n = new

$$R_o = Z\cos\theta \qquad X_o = Z\sin\theta$$

If angle negative, then B_o negative

$$G_o = \frac{R_o}{R_o^2 + X_o^2} \qquad B_o = \frac{X_o}{R_o^2 + X_o^2} \qquad X_n = X_c - X_l$$

If X_n negative, then B_n negative

$$G_n = \frac{R_n}{R_n^2 + X_n^2} \qquad B_n = \frac{X_n}{R_n^2 + X_n^2} \qquad \theta = \arctan\frac{B_t}{G_t} \quad \boxed{-60.2}$$

$$B_t = B_o + B_n \qquad Y = \sqrt{G_t^2 + B_t^2}$$

$$G_t = G_o + G_n \qquad Z = \frac{1}{Y} \quad \boxed{13.2512924}$$

Notes:
In a parallel circuit, voltage is used as a reference and the currents in each leg are the vector quantities. Accordingly, inductive impedance will have a negative angle.

FIGURE 1.19
Parallel Impedance

as positive instead of negative as a result of the change in reference from current to voltage. The second leg has a 5 ohm resistor in series with an 11.3 ohm inductance. As presented in Figure 1.3 on parallel resistors (reciprocal of the sum of the reciprocals for like components), a somewhat similar procedure will applied for parallel impedance. The reciprocal of a leg with pure resistive ohms is labeled conductance or G, pure reactance ohms as susceptance or B, and total impedance ohms as admittance or Y. However, if the leg has mixed reactance and resistance, the expression for G is equal to $R/(R^2 + X^2)$, and B becomes $X/(R^2 + X^2)$. The old leg is reduced to the R and X components by using the cosine of the angle to determine R and the sine of the angle for the X component. Because of the change in reference—voltage instead of current—inductive quantities are assigned a negative value. The G and B are determined for each leg, and then the square root of the total G^2 plus the total B^2 is calculated to determine the circuit Y. The reciprocal of Y equals the total circuit impedance Z, and the angle can be determined by the arctangent of B/G. The right triangle relationships are shown in Figure 1.20 and intrude

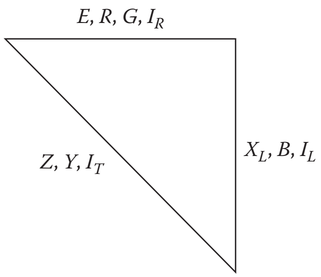


FIGURE 1.20
Parallel Impedance Inductive Circuit Triangle

into the fourth quadrant to represent an inductive circuit. The final output of the calculation represents an equivalent simple inductive series circuit that could now be represented in the first quadrant if desired by using current as the reference.

1.14 Transformers

The first closed iron core transformer was built by Westinghouse in 1886 based on a patent secured by William Stanley. Figure 1.21 represents a simple closed core transformer. The source side is called the *primary,* and the load side is called the *secondary.* Without load, an excitation current flows in the primary that is limited by the primary impedance. The excitation current is expressed as a percentage of full load amps and produces a magnetic flux (mutual flux) based on the ampere turns in the primary side, which also links with the secondary winding through the core iron. The magnetic flux induces a voltage in the secondary side proportionally to the relative number of turns in the winding. The secondary voltage magnitude is the transformer ratio (primary turns/secondary turns) divided into the primary or source voltage. The secondary voltage can be higher or lower depending on

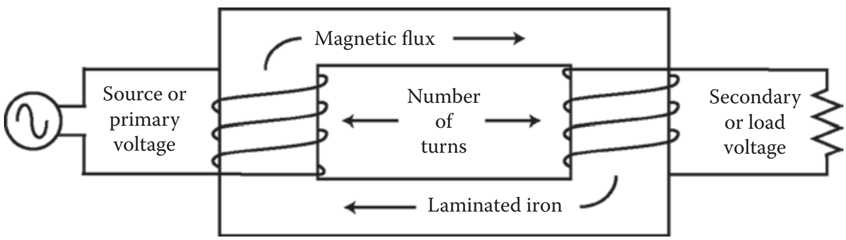


FIGURE 1.21
Simple Transformer

the respective number of turns or winding ratios. An increase in the number of turns in the secondary winding increases the voltage.

When a transformer is loaded, the secondary winding current produces a magnetic flux that opposes the flux originating in the primary winding. This counter or opposing flux reduces the impedance of the primary winding, allowing additional current to flow from the source; in this way, the transformer is self-regulating. The secondary current flow magnitude is also dependent on the ratio (primary turns/secondary turns) and the secondary current can be determined by multiplying the primary current (excluding excitation current) by the turns ratio. The winding with the lower number of turns will have the higher current flow. Hyphens or black dots are commonly used to represent primary/secondary polarity marks and provide the relative instantaneous direction of current flow. The general rule is current flows into the polarity mark on the primary side will produce current flows out of the polarity mark on the secondary side (in on polarity and out on polarity). For phasor (time dependent vector) or vector purposes, the direction of current flow is in agreement with the direction of power flow from the source to the load.

The short circuit ohms of a transformer can be determined by test. A jumper or short circuit is applied across the secondary winding, and the primary voltage that allows full load amps to flow can be measured. This voltage is denoted as an impedance voltage drop. The primary impedance ohms of the transformer can then be determined by dividing the voltage drop by the full load amps. The same test process can be reversed to determine the impedance ohms on the secondary side. Because the primary and secondary side will have different ohmic values, impedance values are normally expressed as a percent impedance or percentage value that will work on both sides. The per-unit impedance is determined by dividing the impedance voltage drop by the rated voltage or nominal or mid-tap position for tapped windings. Multiplying the per-unit value by 100 yields the %Z of the transformer and will normally be provided on nameplates for power transformers. The impedance of the secondary or load can be reflected to the primary side by the following expression:

$$Z \text{ primary} \times (\text{secondary turns})^2 = Z \text{ secondary} \times (\text{primary turns})^2$$

Because apparent power, volt-amps (VA), as the symbol indicates, is a product of volts times amps, the amount of current required for a given VA can be reduced by using a transformer to step up the voltage to a higher level. This is convenient for transferring power long distances to reduce losses and to permit smaller conductors for transmission purposes and also in the design of large motors and generators. Neglecting losses, a transformer's primary VA is equal to its secondary VA.

1.15 Electrical Systems

Besides increasing voltage, transformers are also used to step down transmission, sub-transmission, and distribution voltages to more practical levels for the particular applications, that is, industrial, commercial, and residential loads. The trade-off with increasing the voltage is the insulation system needs to be able to withstand the higher voltage. In the case of generators, an increase in excitation or magnetic flux would also be required to produce a higher voltage, and there are design trade-offs involved with selecting a particular voltage. Probably, the most common voltage for a large generator would be 18 kV (medium voltage); for transmission, 230 kV (high voltage); for sub-transmission, 69 kV (medium voltage); and for distribution, 12 kV (medium voltage). For overhead conductors, the economics generally favor 1 kV per mile of distance. In other words, the foregoing voltages were probably selected for roughly transferring power 230, 69, and 12, miles, respectively. Large industrial plants feed their loads with different voltages depending on the horsepower (HP) of connected motors; typical ranges for switchgear fed motors are 75 to 299 HP for 480 volt (low voltage) buses, 300 to 5000 HP for 4 kV (medium voltage) buses, and 6.9 kV or 13.8 kV (medium voltage) for motors greater than 5000 HP. Commercial facilities are commonly fed with 480 volts, and residential customers with 220/110 volts.

Figure 1.22 illustrates a simplified one-line view of a typical utility system. The 230 kV high voltage transmission system is part of a bulk power electrical network that has multiple geographically dispersed sources of generation and substations. It is used to link large areas together for reliability and economic reasons and may be composed of multiple utilities and states. Medium voltage 69 kV sub-transmission systems are normally fed from a single 230/69 kV substation that is operated by a single utility in an isolated mode and not paralleled with other sub-transmission systems. In recent years, with the advent of peaking units, distributed generation, cogeneration (CHP) and renewables, it has become much more commonplace for sub-transmission systems to also have sources of generation. Sub-transmission systems feed large industrial customers and multiple receiving or distribution substations over an isolated network that may cover a county or portion of a large county. The 12 kV distribution substations serve much smaller areas with the majority of the loads coming from smaller industrial, agriculture, commercial facilities, and residential homes. The 12 kV distribution lines radiate out from their respective substation and consequently, are referred to as radial systems. The term *radial* is also used to describe non-network isolated electrical systems used for auxiliary power for large industrial plants and generating stations.

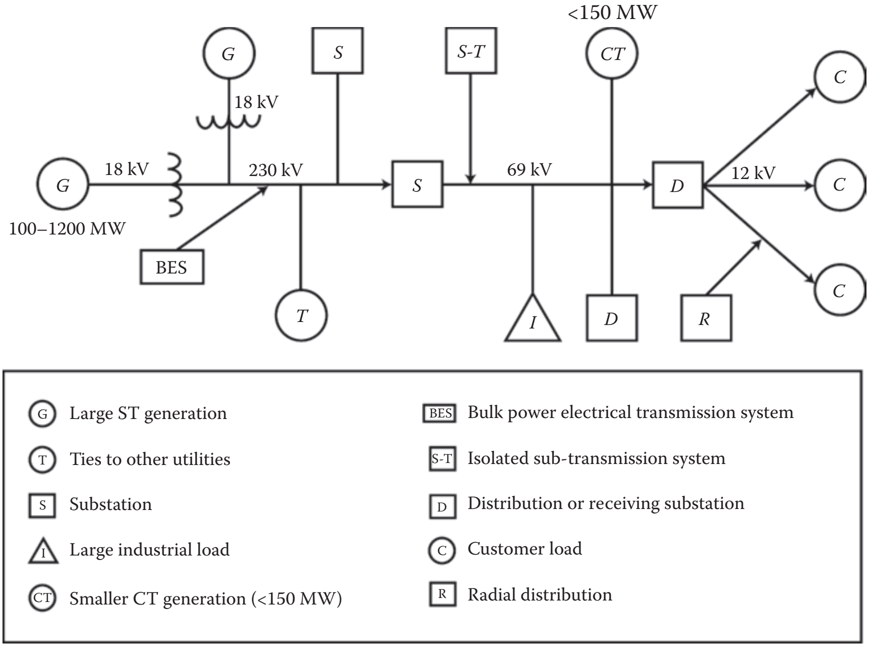


FIGURE 1.22
Typical Utility Configuration

1.16 Generating Station Electrical Configurations

Figures 1.23 and 1.24 present the more common electrical configurations for a large fossil steam turbine (ST) generating station connected to the bulk power electrical system (BES) at 230 kV and a smaller combustion turbine (CT) plant connected to sub-transmission at 69 kV. In both cases, a generator step-up transformer (GSUT) increases the output voltage for connection to transmission or sub-transmission systems, plant medium voltage 4 kV auxiliary power buses are being fed by unit auxiliary transformers (UATs), and plant low voltage 480 V buses are fed from the 4 kV buses through station service transformers (SSTs). In the past, providing a generator bus breaker for a large generating unit was cost prohibitive because the short circuit current is very high at that location; today, with advances in circuit breaker interrupting technology, it is much more affordable. The application of generator bus circuit breakers started to be more prominent in the 1970s with the advent of combustion turbine units that were smaller in size.

The large fossil unit is equipped with a reserve auxiliary transformer (RAT). This transformer is directly connected to the local 230 kV switchyard and is provided for startup power purposes; once a parallel or synchronization operation connects the unit with the BES, the load is transferred to

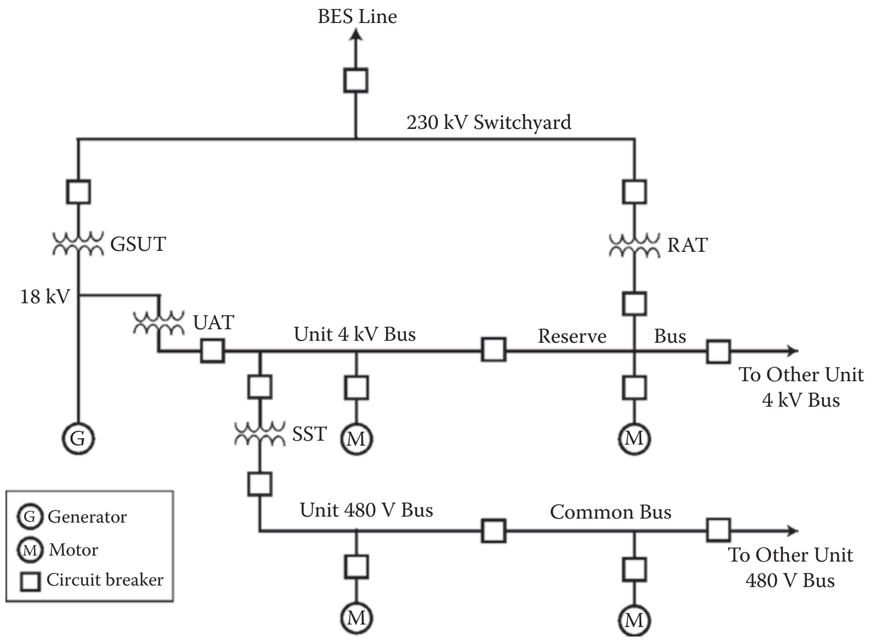


FIGURE 1.23
ST Generating Station Simplified One-Line

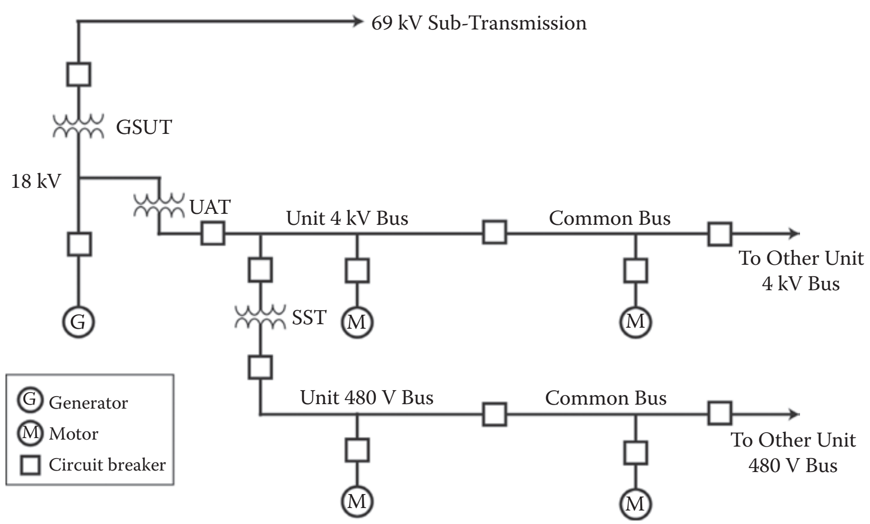


FIGURE 1.24
Combustion Turbine (CT) Plant Simplified One-Line

the UAT. UAT loads are more critical to the operation of the unit and the RAT bus would normally be used to feed less critical balance of plant loads. Depending on the size of the unit and design details involving costs, short circuit currents, voltage drops, and reliability, there may be multiple UAT and SST transformers or windings that feed multiple isolated buses. Because the combustion turbine unit is equipped with a generator bus breaker that isolates the machine when the unit is off-line, startup power can be provided by simply backfeeding through the GSUT.

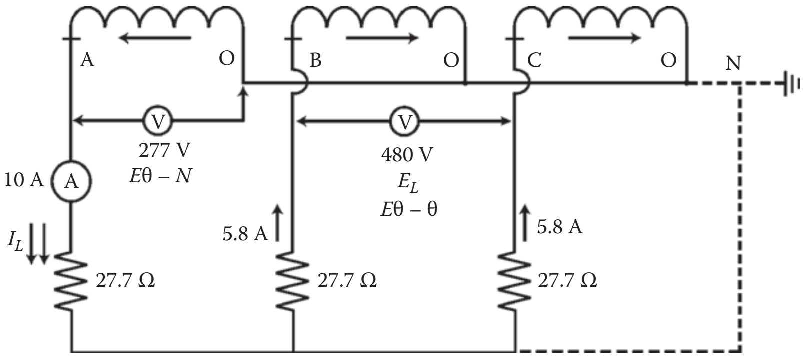
1.17 Three-Phase Basics

Figure 1.25 illustrates a wye winding connection, a balanced wye connected resistive load, and the related mathematical expressions and phasor relationships. The wye winding connection could be associated with either a generator or transformer. The mathematical calculations assume a balanced load and, in that case, neither the dashed earth ground connection nor the dashed connection to the common point of the load can affect the results.

The voltage from each winding or phase (277 V) is displaced by 120 degrees. The phasor wheel shows A0 hitting a peak at 90 degrees, and B0 at 330 degrees, followed by C0 at 210 degrees. The outside or arrowhead of each phasor is the phase letter and 0 represents the inside or common or neutral point. The phase sequence is ABC with a counterclockwise rotation. Three phase-to-phase voltage combinations are presented—AC, BA, and CB—and each can be determined by following the circular arrow on the inside of the delta or equilateral triangle. The direction of the circular arrow can also be reversed to determine the three phase-phase combinations (AB, BC, and CA) in the opposite direction. Each phase-to-phase voltage is the vector sum of two winding voltages; for example, AC equals the vector sum of A0 plus 0C. Because A0 and 0C are equal in magnitude and 60 degrees apart, the vector sum equals the square root of 3 or 1.732 times A0 or 480 volts.

Balanced currents of 10 amps resistive flows in each line or phase that are in phase with their associated phase-to-neutral voltages. Each line current is derived from two phase-to-phase combinations as shown by the dashed lines on the phasor wheel. In the case of A phase, an AC current is added to an AB current. Because the two currents are 60 degrees apart, the total is one of the currents multiplied by 1.732 with balanced load. The arrows show how the A phase winding current exits polarity at 10 amps and returns on polarity at the other two windings with a magnitude of 5.8 amps each. This, of course, only shows the current for A phase, and a similar process can be applied to determine the magnitudes and phasor positions for the other two windings.

The total voltage drop per phase can be determined by multiplying the per-phase impedance by the line current. The VA for A phase can be



- $E_L = E\theta - \theta = E\theta - N \times \sqrt{3} = 277 \times 1.732 = 480\ V$
- $3\theta\ VA = 277 \times 10 \times 3 = 8310\ VA$ or $8.31\ kVA$
- Voltage drop $E_R = 10 \times 27.7 = 277\ V$
- $3\theta\ VA = \dfrac{E^2}{Z} \times 3 = \dfrac{277^2/27.7}{1000} \times 3 = 8.3\ kVA$
- $3\theta\ VA = I^2Z \times 3 = \dfrac{100 \times 27.7}{1000} \times 3 = 8.3\ kVA$
- $3\theta\ W = \dfrac{E^2}{R} \times 3 = \dfrac{277^2/27.7}{1000} \times 3 = 8.3\ kW$
- $3\theta\ W = I^2R \times 3 = \dfrac{100 \times 27.7}{1000} \times 3 = 8.3\ kW$

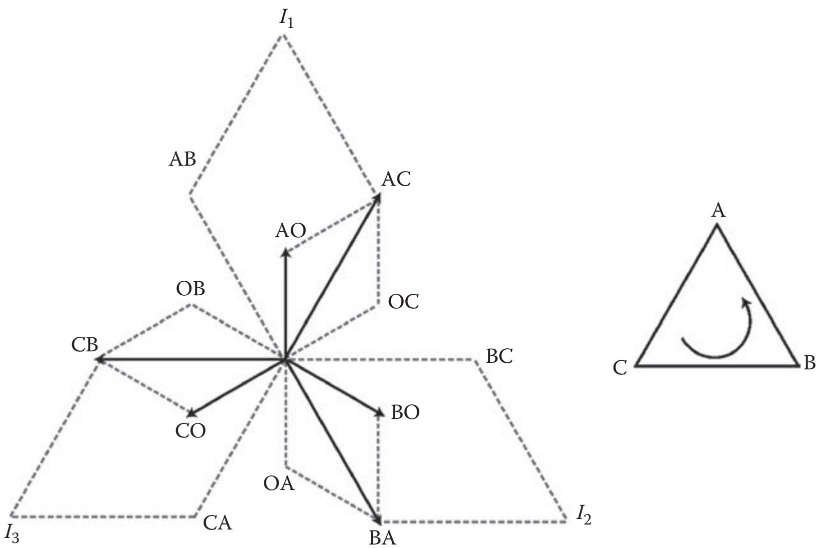


FIGURE 1.25
Wye Configurations and Relationships

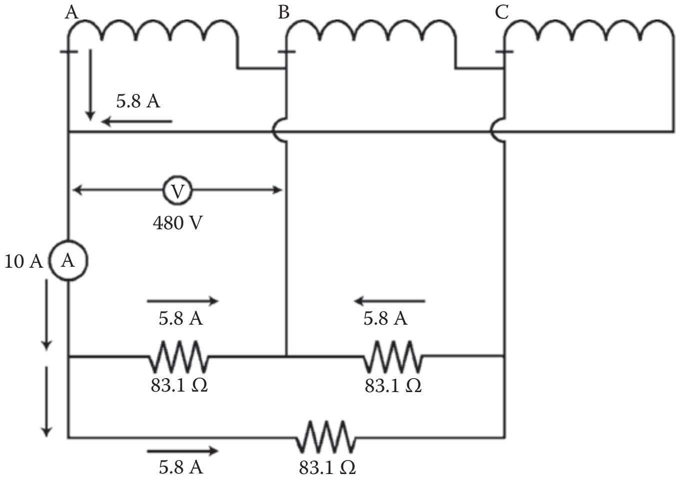
determined by simply multiplying the line current (same as the winding current with a wye connection) by the phase-to-neutral voltage. Because the load is balanced, the VA for A phase can be multiplied by 3 and then divided by 1000 for the total three-phase kVA. The square of the phase to neutral voltage divided by the phase impedance or the square of the current times the line impedance can also be used to determine the per-phase VA and, with balanced loads, multiplied by 3 to determine the total VA. In balanced three-phase power, only the line phase impedance for each conductor and associated load needs to be considered. The return conductor impedance (which involves other phases) can be ignored.

Similar formulas are outlined for determining real power or watts (symbol W) in honor of James Watt (Scottish) who improved steam engine efficiencies in the late 1700s. A watt is one joule per second. A joule (symbol J) is one watt second and is named after James Joule (English) for his work in thermodynamics in the 1800s. In this example, because the load is resistive and there are no angular differences between the voltage and current, the real power equals the apparent power and watts and volt-amps are the same.

Figure 1.26 presents a delta winding connection, a balanced delta connected resistive load, and the related mathematical expressions and phasor relationships. The delta winding connection could be associated with either a transformer or generator, although almost all generators 10 megavolt-amps (MVA) and larger are normally wye connected. As you can see by comparing Figures 1.25 and 1.26, the line currents, the line or phase-to phase voltages, the total kVA values, and the phasor wheels are all identical. In addition to the delta winding and load configurations, there are also differences in current flows internal to the windings and load, the load ohmic values, and how the kVA magnitudes are developed in the figures.

For both the delta connected transformer and delta connected load, each phase line current has two possible paths. For balanced conditions, the current in each path, transformer, or load can be determined by dividing the total line current by the square root of 3 or 1.732. The actual load current for each leg of the delta can also be determined by dividing the line voltage by the impedance associated with the particular leg

The phasors or vectors for both figures have the same alignment. A phase-to-neutral voltage is still represented even though the transformer delta winding configuration does not have a neutral. Figure 1.27 shows how to convert the balanced wye load impedance of Figure 1.25 to the equivalent delta configuration shown in Figure 1.26. Conversely, the delta load impedance in Figure 1.26 can be divided by 3.0 to reestablish the original wye impedance. With the load in a wye configuration, it can easily be seen that the IR or voltage drop will be in phase with the phase-to-neutral voltage shown on the phasor wheel. The delta or equilateral triangle represents a transposition that shows the angular relationships of the phase-to-neutral voltages for the 480 volt delta windings. With phasors, it is customary to use voltage as the reference and shift the currents to show angular differences



$$3\theta\ VA = \frac{480 \times 5.8}{1000} \times 3 = 8.3\ kVA$$

$$3\theta\ VA = \frac{E^2}{Z} \times 3 = \frac{480^2/83.1}{1000} \times 3 = 8.3\ kVA$$

$$3\theta\ VA = I^2 Z \times 3 = \frac{5.8^2 \times 83.1}{1000} \times 3 = 8.3\ kVA$$

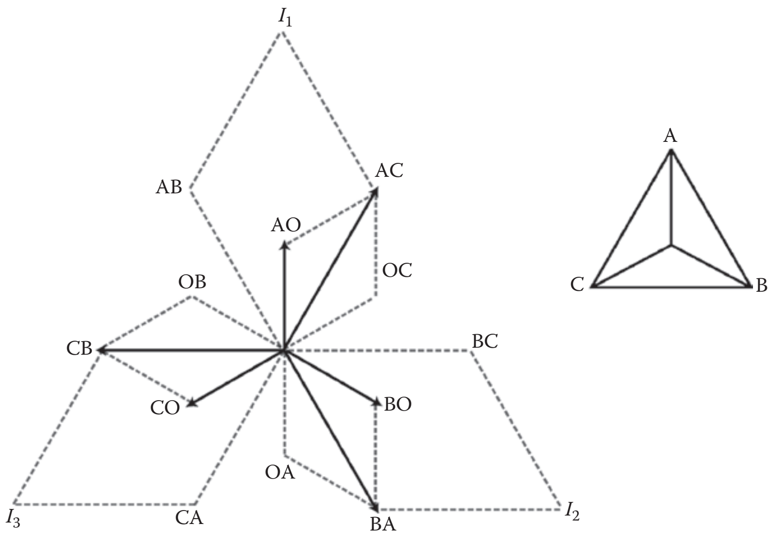


FIGURE 1.26
Delta Configurations and Relationships

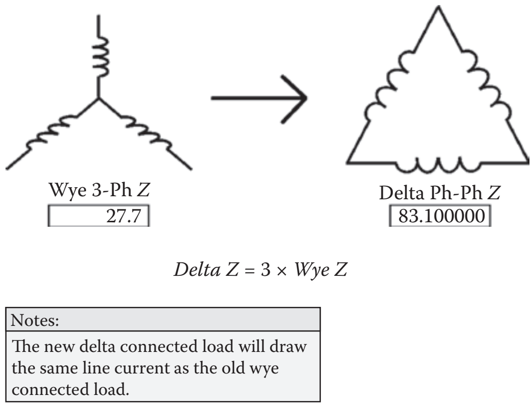


FIGURE 1.27
Wye Delta Conversion

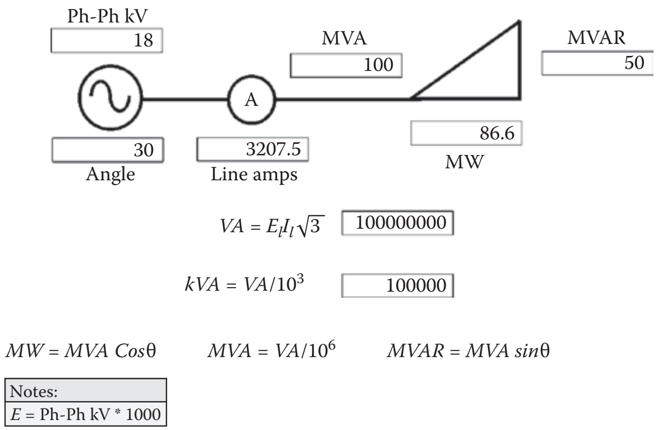


FIGURE 1.28
Angle to MVA and MW

between the two quantities from inductive or capacitive loading. One rationale for this is the source normally feeds a number of different legs and, consequently, represents a parallel circuit.

The kVA expressions are similar, have the same calculated magnitudes, but are a little different because they are using current magnitudes inside the delta load instead of line or per phase quantities. Both the E^2/Z and the I^2Z expressions can be used to determine the VA for one leg of the delta. The results are divided by 1000 to convert VA to kVA and then multiplied by 3 for a total three-phase kVA. Because the load is purely resistive, the phase-to-phase current will be in phase with the phase-to-phase voltage.

Figure 1.28 covers a more common approach for determining three-phase volt-amps, watts, and vars that is transparent to actual transformer winding

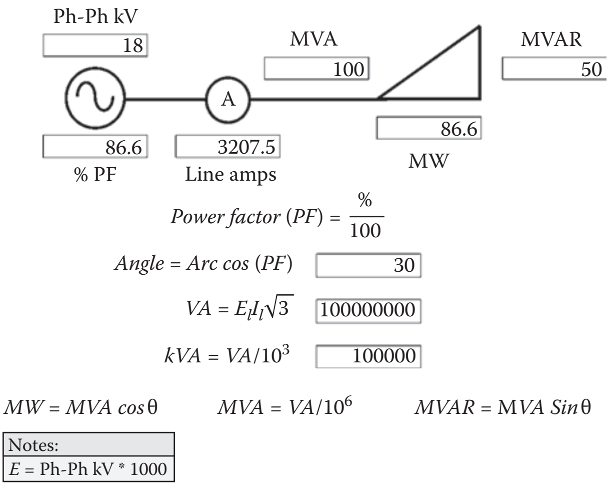


FIGURE 1.29
Power Factor Percent to MVA and MW

and load configurations as long as the loads are balanced and the measurements are confined to line quantities, that is, phase-to-phase or line voltage and line current. Vars (volt-amps-reactive) are shown at the opposite side of the right triangle relationship in Figure 1.28. They can be calculated using the sine of the angle as presented in the figure or using an I^2X or $(E\ \text{phase-n})^2/X$ expression times 3. Normally the power output of generating station transformers, that is, GSUT, UAT, RAT, and SST transformers, is reasonably balanced.

Percent power factor is the cosine of the angle between the phase-to-neutral voltage and the line current multiplied by 100 and has to be considered for calculating watts. The loads for Figures 1.25 and 1.26 are purely resistive, and the currents and voltages are in-phase; this is referred to as unity power factor because the cosine of 0 is 1 or 100%. Usually, the angle is somewhere around 30 degrees or 86.6% power factor lagging due to the inductive nature of transformers and motor loads.

Figure 1.29 is almost identical to Figure 1.28 except percent power factor is used in the first part of the calculation sequence instead of angle. As mentioned before, power factor is the cosine of the angle between current and voltage. The arc-cosine of (percent power factor/100) will yield the angle and the remaining calculations are the same.

Today, in the United States there are two phase rotation sequences that are used by large utilities. Figure 1.30 shows both: (a) represents CBA or 321, and (b) represents ABC or 123. In the case of (a), A and C phases displayed in (b) are swapped. In reference to (b), because vector rotation is counterclockwise, first A phase voltage peaks, followed by B 120 degrees later, and then followed by C 240 degrees later. Although ABC is more prevalent in

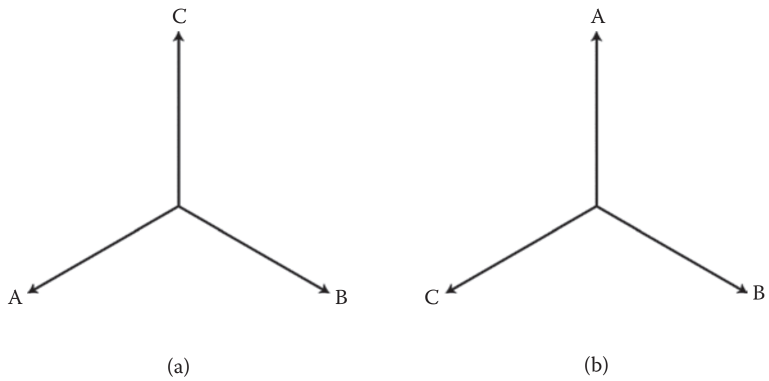


FIGURE 1.30
Phase Rotation Sequence

the industry, several large utilities do use the phase sequence rotation presented in (a). In the case of (a), motors will operate in a reverse rotation mode, and care needs to be taken to ensure that protective relay functions are not impacted by the sequence change.

1.18 Power Transformer Connections

Figure 1.31 displays the phase-to-neutral voltage relationships for a large utility. As you can see, their bulk power electrical system voltages (115, 230, and 500 kV) are in phase, the sub-transmission voltages (33 and 69 kV) lead by 30 degrees, and the distribution voltages (12 and 16 kV) lead by another 30 degrees.

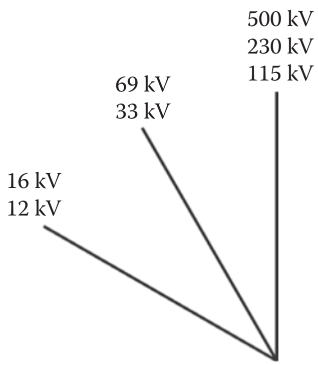


FIGURE 1.31
Phase-to-Neutral Voltage Relationships

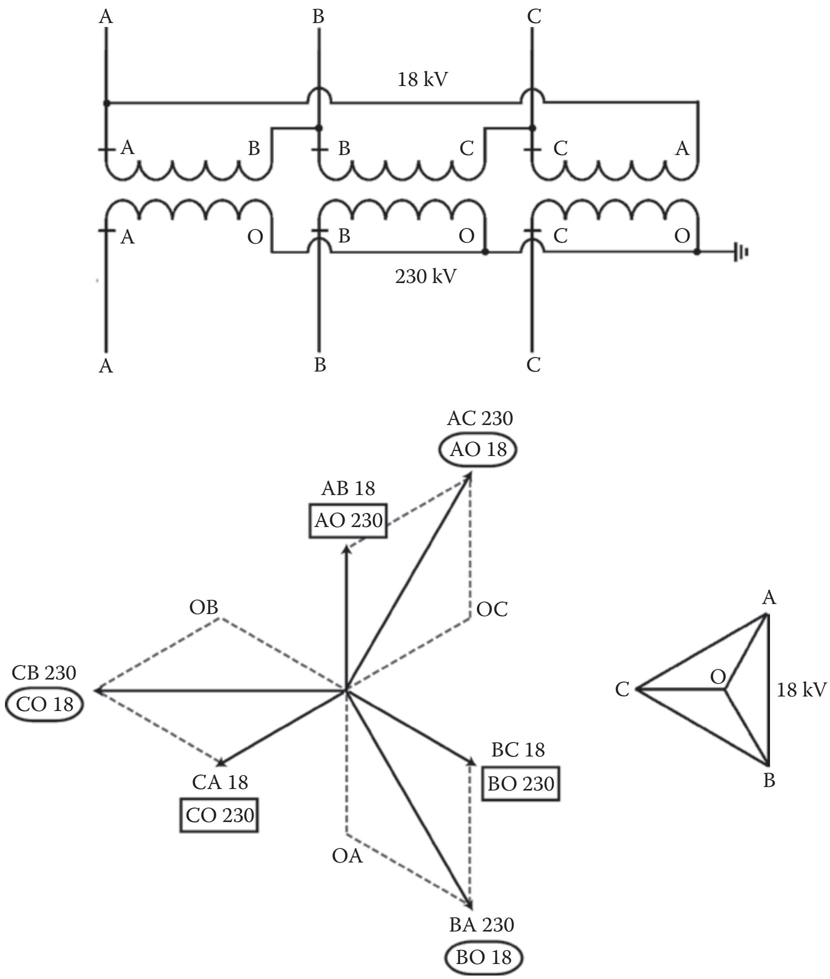


FIGURE 1.32
Delta-Wye Leading Connection

Figure 1.32 illustrates a delta-wye transformer configuration. A delta-wye connection is almost always used for GSUT and UAT transformer applications presented in Figures 1.23 and 1.24. In both cases, the delta primary windings would be on the 18 kV or generator side to avoid ground fault currents that could damage the generator stator iron. The transformer windings do not cause a phase shift; the primary winding voltage is in phase with the secondary winding voltage. In the case of A phase, the AB 18 kV voltage for the primary is across from and in phase with an A0 voltage on the secondary or 230 kV side. In regard to Figure 1.23 where generator parallels with the electrical system are made by closing a 230 kV breaker, those voltages could be used for synchronizing purposes. However, there is phase shift between

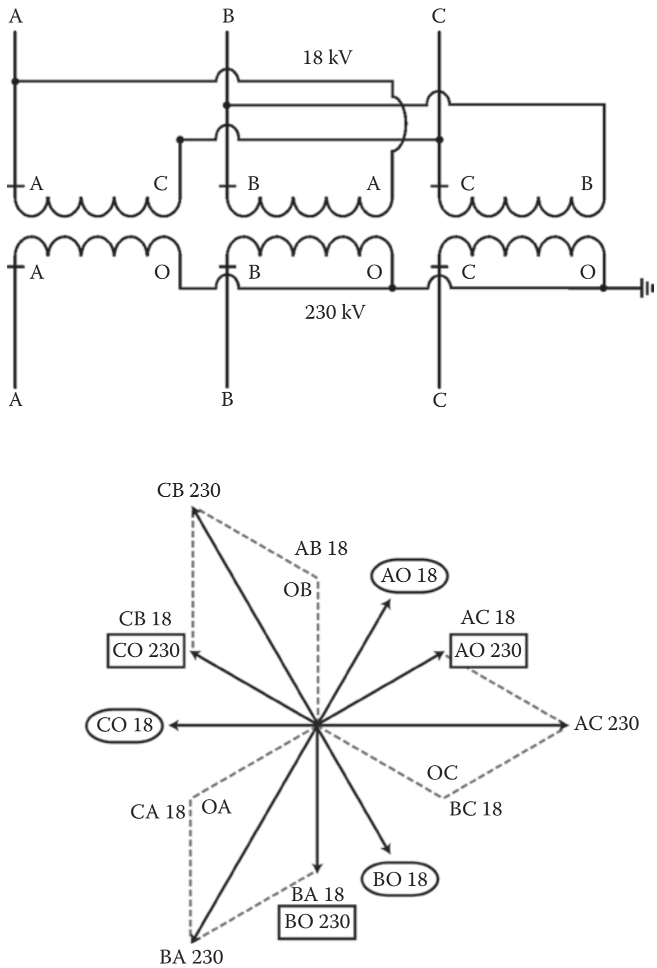


FIGURE 1.33
Delta-Wye Lagging Connection

the phase-to-neutral voltages on each side of the transformer. A0 230 kV leads A0 18 kV by 30 degrees and consequently represents a leading connection. The phase-to-phase 230 kV voltages are determined by taking the vector sum of a phase-to-neutral voltage from one phase and a reverse voltage from another phase. For example, AC current flow exits on polarity for the A phase winding and exits on nonpolarity for the C phase winding, which is the reason for reversing the C phase vector. The phase-to-neutral 18 kV voltages are determined by drawing or transposing the phase-to-phase phasors into a delta form and then extrapolating the corresponding phase-to-neutral voltages as shown in the figure. For a wye-delta configuration, with 230 kV on top and 18 kV on the bottom, the process would be the same and the outcome

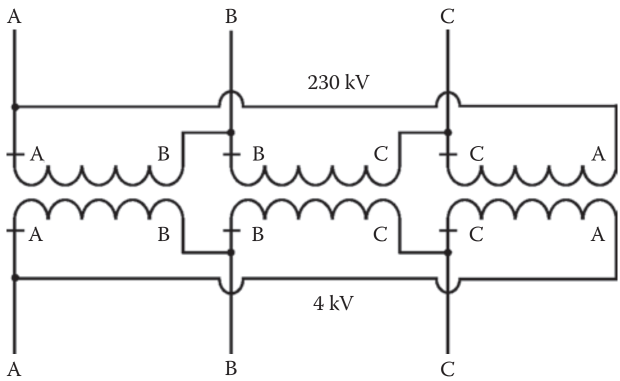


FIGURE 1.34
Delta-Delta Connection

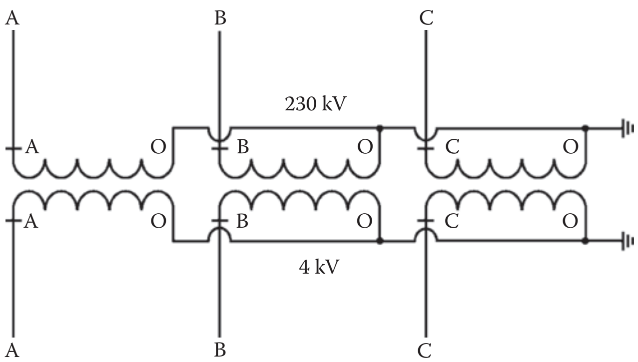


FIGURE 1.35
Wye-Wye Connection

or phasor relationships would also be the same as long as the connections are not changed. The leading connection could be used to develop the 30-degree system voltage relationships between bulk power and sub-transmission and between sub-transmission and distribution presented in Figure 1.31.

A lagging connection is shown in Figure 1.33. The phasor or vector procedure is the same, but A0 230 kV is now in phase with AC instead of AB, which causes A0 230 to lag A0 18 instead of lead.

If a leading delta-wye connection is used for both the GSUT and the UAT, the 4 kV would be in phase with the 230 kV and a connection that does not provide a phase-to-neutral shift between the primary and secondary would be required for the RAT of Figure 1.23. An in-phase connection could be provided by a delta-delta transformer configuration (Figure 1.34), a wye-wye transformer bank (Figure 1.35), or a delta-wye zigzag transformer configuration (Figure 1.36). The delta-delta could be used if an independent ground

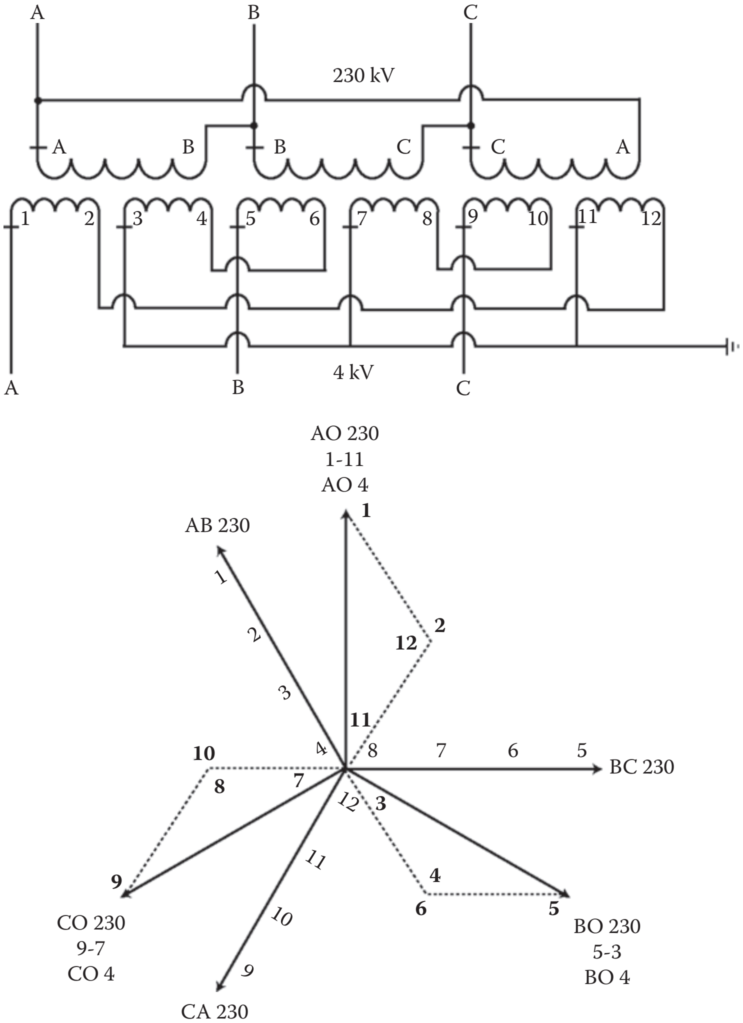


FIGURE 1.36
Delta-Wye-Zigzag Connection

bank is applied for ground tripping or alarm purposes on the 4 kV side; the wye-wye for ground schemes (if both neutrals are grounded), and the delta-wye zigzag where there is concern over third harmonic levels with wye-wye connections. Because the neutral does not normally carry load in a generating station and ground fault currents are usually limited, concern about third harmonic levels are reduced. Third harmonic levels in wye-wye configurations can also be mitigated with delta connected tertiary windings that circulate harmonics or through improved core iron designs that reduce the third harmonic levels.

The easiest way to vector the delta-wye-zigzag connection in Figure 1.36 is to start with the secondary phase connections. Using A phase as an example, the 1 end of the 1-2 winding is connected to the A0 phasor and provides a 30-degree leading voltage. By analyzing the phasors, it can be determined that the 12-11 voltage provides a lagging voltage; the vector sum of the 1-2 and 12-11 voltages results in a secondary phase-to-neutral voltage that is in phase with the primary phase-to-neutral voltage. A similar process can be applied to the other secondary phases. If 1, 5, and 9 represent the secondary phase connections, 12 and 2, 6 and 4, and 10 and 8 can be tied together, respectively. The neutral connection can then be made by connecting 3, 7, and 11 together.

1.19 Instrument Transformer Connections

Instrument transformers are required to reduce voltage and current levels to practical magnitudes for revenue metering, monitoring, and protective relay applications. The most common connections for voltage or potential transformers (VT or PT) are open delta and wye-wye. As mentioned previously, there is no phase shift with the wye-wye connection. Figure 1.37 shows a typical open delta connection. As the phasor wheel indicates, AB 18 kV is in phase with B1-2. Some utilities use B1 to indicate an A phase secondary voltage or potential. For most applications, the primary phase-to-phase voltage is reduced to 115 or 120 volts on the secondary side. The secondary arrows show a reverse current flow for the B3-1 potential. Accordingly, the phasors for both B2-3 and B1-2 are reversed to a B3-2 and B2-1, respectively, and the vector sum results in the B3-1 voltage. Because they are 120 degrees apart, the secondary voltage magnitude is not impacted, but there is an angular change as shown on the phasor wheel.

The most common current transformer configuration is a wye connection as illustrated in Figure 1.38. Some utilities use A1 to indicate an A phase secondary current with A4, denoting the neutral or star point conductor. Current transformer ratios are usually shown with 5 amps on the secondary side, that is, 3000/5 for a turns ratio of 600/1. Five amps is the continuous current thermal rating of current transformers with rating factors of 1. A current transformer with a rating factor of 3.0 would have a continuous current rating of 15 amps. Most current transformers resemble a donut with the primary conductor going through the opening. It is basically a transformer with one turn in the primary and multiple turns on the secondary side. It will work in reverse if the primary is shorted and current flows in the secondary, but the driving voltage is low and consequently the impedance of the primary shorting conductors would also have to be low.

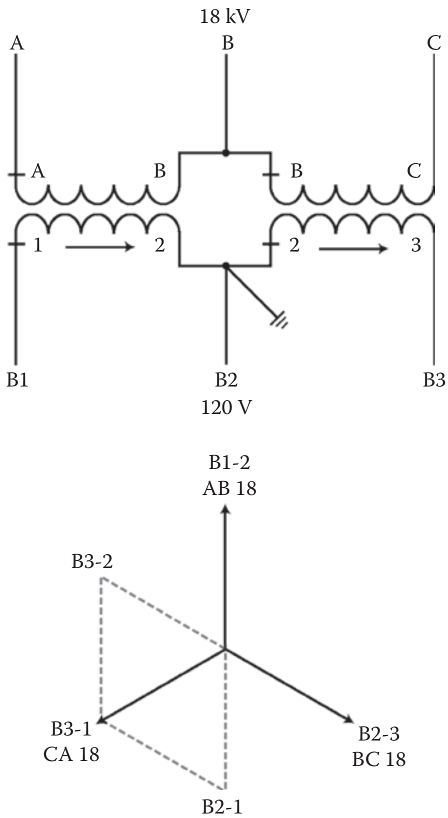


FIGURE 1.37
Open Delta Connection

For phasor purposes, the current is referenced to the direction of load flow, and the load is assumed to be at unity power factor where the current is in phase with the phase-to-neutral voltage. The polarity marks are shown, and primary currents into polarity develop secondary currents i1, i2, and i3 that exist on polarity as shown on the phasor wheel. Accordingly, an A4-1 current would be in phase with an A0 primary voltage.

For delta-wye electromechanical transformer differential schemes, delta connected current transformers are needed on the wye side of the transformer to bring the currents back into phase because of the 30-degree phase shift in the power transformer connection. With newer digital relays, the phase angle differences can be accounted for in the software and wye connected current transformers can be used on both sides of the transformer. Figure 1.39 shows the connections and phasors for both 30-degree lead and lag current transformer connections. In the case of A phase, the vector sum of i1 minus i2 produces a current that leads the phase-to-neutral voltage

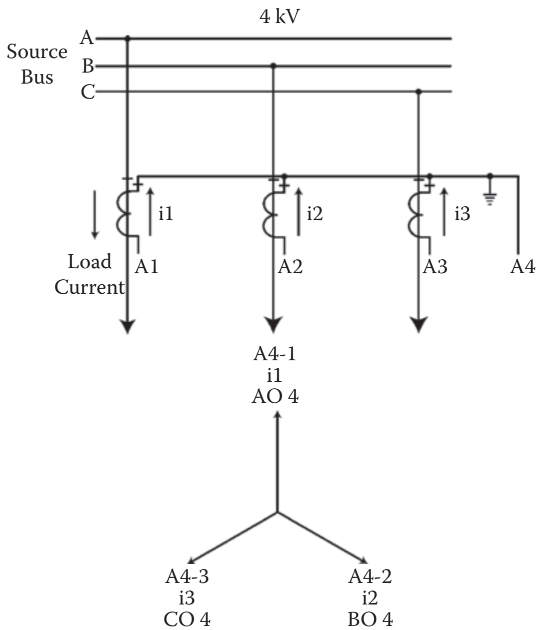


FIGURE 1.38
Current Transformer Wye Connection

by 30 degrees as illustrated under (a). Under (b) the vector sum of i1 minus i3 develops a secondary current that lags the phase-to-neutral voltage by 30 degrees. In both cases, the delta CT connection increases the magnitude of balanced secondary current flows in A1, A2, or A3 by the square root of 3 or 1.732. The secondary currents for each phase enter their current transformers through A1, A2, and A3, respectively.

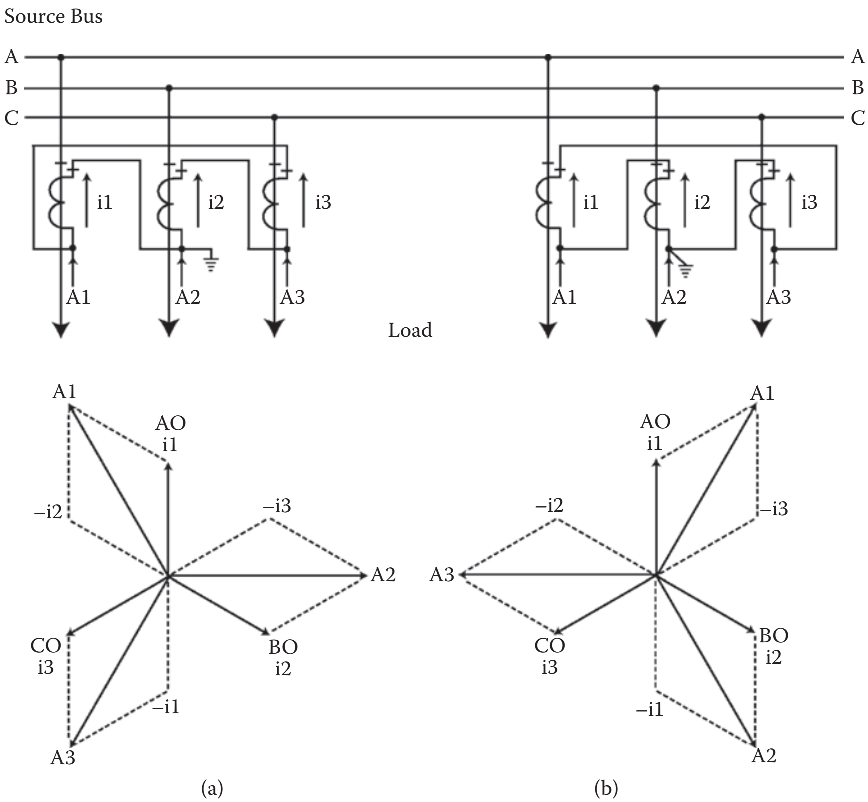


FIGURE 1.39
Current Transformer Delta Lead and Lag Connections

1.20 Bibliography

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2

Electrical Studies

Electrical engineers that support generating stations and large industrial facilities will periodically need to complete studies that address operational considerations and design issues for betterment projects. This chapter covers the theoretical basics for power system analysis and provides examples for voltage, power transfer, and short circuit studies.

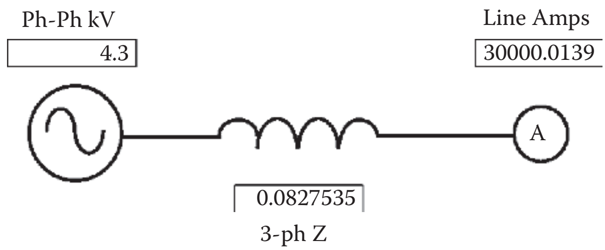
2.1 Conversions

When performing electrical studies, a good starting point is to find out the short circuit duty at the source. In the case of a generating station, the source would be the high voltage switchyard associated with the particular plant, and subsequent calculations would start from that location. Short circuit duty can be expressed as current (amps), impedance (ohms), or apparent power (megavolt-amps, or MVA). Accordingly, electrical power engineers need to be able to convert from one form to another as required for the specific calculation.

2.1.1 Ohmic

In Figure 2.1, balanced three-phase impedance is converted to amps, and the inverse calculation is shown in Figure 2.2. Both formulas are basically three-phase versions of Ohm's Law and are commonly used when performing studies. A typical three-phase short circuit current level for large generating station 4 kV and for 480 volt main unit buses is 30,000 amps. For the 4 kV bus, the total short circuit impedance, including the 230 kV system, the unit auxiliary transformer (UAT) or reserve auxiliary transformer (RAT) impedance, and the busway or cable impedance from the UAT or RAT to the bus, would have a value of less than 0.1 ohms.

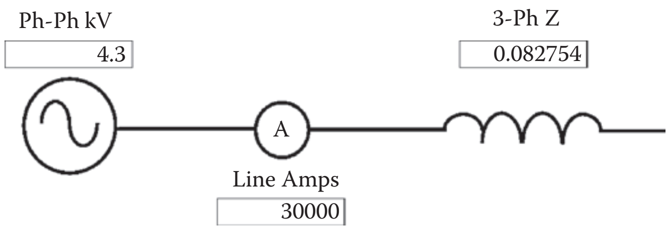
Balanced conditions are assumed for most studies and in that case, three-phase Z is equal to Z phase to neutral (E phase-n/I), and both quantities are interchangeable. Three-phase Z is assumed to be in a wye configuration. Ohmic values for cables and busways are typically given for one line or phase and correspondingly are equivalent to phase-to-neutral values or



$$I_l = \frac{E_l}{\sqrt{3}\,Z}$$

Notes:
E_l = Ph-Ph kV × 1000
3 Ph Z = Z Ph-N for balanced conditions.

FIGURE 2.1
Z to Amps Conversion



$$3\text{-}Ph\ Z = \frac{E_l}{\sqrt{3}\,I_l}$$

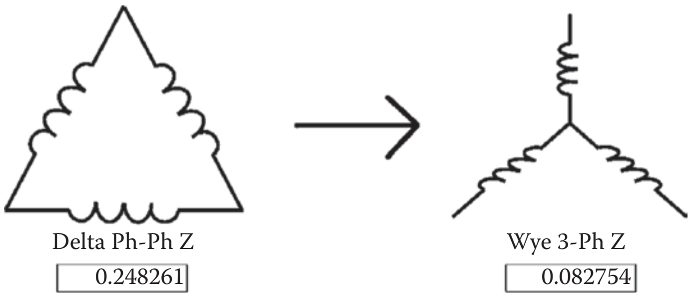
Notes:
E_l = Ph-Ph kV × 1000
3 Ph Z = Z Ph-N for balanced conditions.

FIGURE 2.2
Amps to Z Conversion

wye connections for three-phase short circuit analyses. In Figure 2.3, a delta configuration is converted to a wye connection. Load or line currents for the before and after delta-wye conversion will have the same magnitudes.

2.1.2 Megavolt-Amps (MVA)

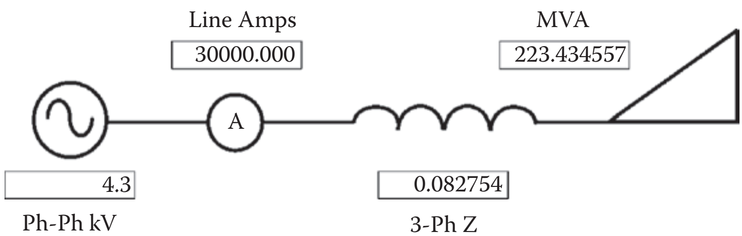
By convention, when MVA is used to express short circuit duty, the three-phase balanced apparent power formula is used to determine current magnitudes for both balanced and unbalanced faults. Figures 2.4, 2.5, and 2.6



$$Wye\ Z = \frac{1}{3}\ Delta\ Z$$

Notes:
The new wye connected load will draw the same line current as the old delta connected load.

FIGURE 2.3
Delta to Wye Z



$$I_l = \frac{MVA \times 10^6}{\sqrt{3}\,E_l}$$

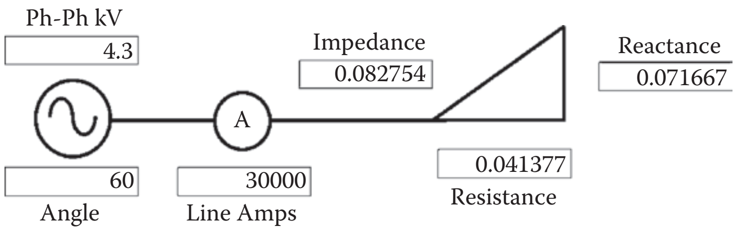
$$Z = \frac{E_l}{\sqrt{3}\,I_l}$$

Notes:
E = Ph-Ph kV * 1000

FIGURE 2.4
MVA to Amps and Z

cover balanced three-phase conversion calculations for MVA, amps, and ohms, respectively.

By analyzing the foregoing figures, you will find that 30,000 amps is equal to .083 ohms, which is equal to 223 MVA. All three parameters can be used to describe the same short circuit magnitudes for 4.3 kV three-phase balanced conditions.



$VA = E_l I_l \sqrt{3}$ 223434554

$kVA = VA/10^3$ 223434.554

$MVA = VA/10^6$ 223.435

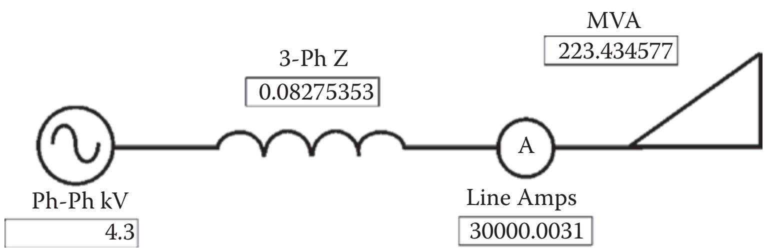
$R = Z Cos\,\theta$

$3\text{-}Ph\ Z = \dfrac{E_l}{\sqrt{3}\, I_l}$

$X = Z Sin\,\theta$

Notes:
E = Ph-Ph kV * 1000

FIGURE 2.5
Amps to MVA and Z



$$I_l = \frac{E_l}{\sqrt{3}\, Z}$$

$$MVA = \frac{E_l I_l \sqrt{3}}{10^6}$$

Notes:
E = Ph-Ph kV * 1000
3 Ph Z = Z Ph-N for balanced conditions.

FIGURE 2.6
Z to MVA

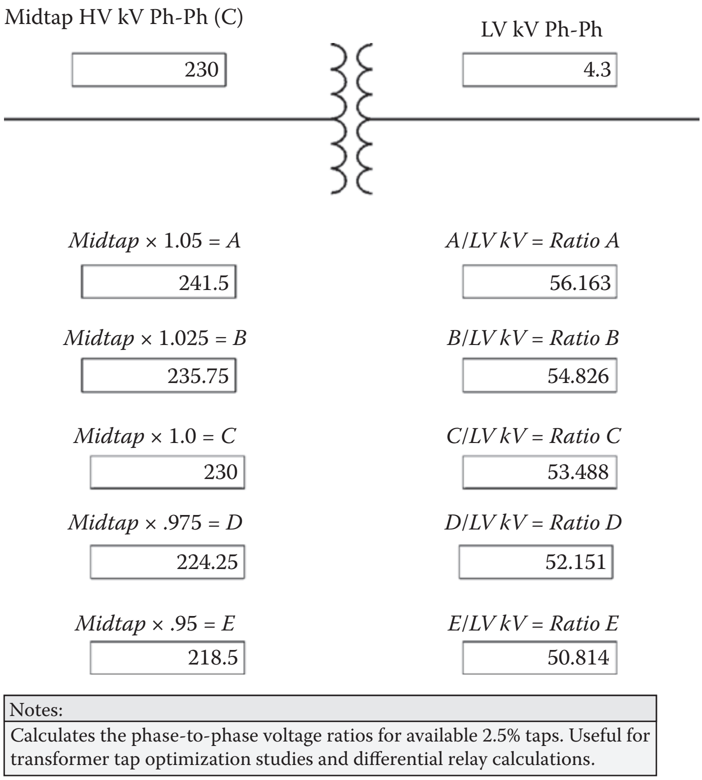


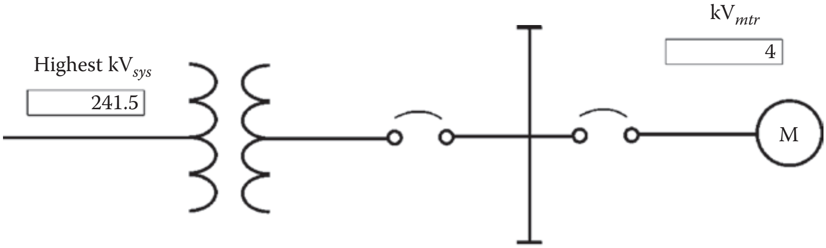
FIGURE 2.7
Transformer Winding Tap Ratios

2.2 Transformer Tap Optimization

The second phase for electrical studies usually involves optimizing transformer winding tap positions, as any changes in ratio will impact the studies.

If the annual peak primary voltage is known, an optimum tap can be selected for the transformer under study. If measured data are not available, a peak voltage of 105% of nominal can be assumed, that is, 230 times 1.05 = 241.5 kV. As presented in Figure 2.7, transformers normally have five no-load tap positions, two above mid-tap, and two below. Each step or tap change increases or reduces the mid-tap voltage ratio by 2.5%.

Although it is hard to say anything absolute about motors because there are numerous design variations, most motors will run more efficiently at higher voltages. In many cases, the motors will require less stator amps to produce the same horsepower, which reduces the corresponding watt and var losses (amps squared × R and × X, respectively). Also, operating at higher voltages provides additional margin for system low voltage conditions. The limiting



Highest allowable secondary $kV_{\text{sec}} = 1.1 \times kV_{mtr}$ 4.4

Lowest allowable Ph-Ph Ratio $= \dfrac{kV_{sys}}{kV_{\text{sec}}}$ 54.886364

Notes:
The calculation has some margin in the no source or feeder voltage drops are considered.

FIGURE 2.8
Transformer Winding Tap Optimization

factor is normally the continuous voltage rating of motor loads on the secondary side of transformers. The optimum tap setting provides the highest voltage that will not reduce the life of motors during worst-case operating conditions when the primary voltage is at its highest and the transformer load is low (minimizing the voltage drops in the source transformer and conductors).

The procedure illustrated in Figure 2.8 provides the lowest allowable phase-to-phase voltage ratio that can be applied without exceeding the continuous voltage rating of the motors. The lower the winding ratio, the higher the voltage on the secondary side. Although motors have a continuous voltage rating of 110% of nameplate, the nameplate value is normally below the nominal bus voltage; that is, 480 volt motors have nameplate ratings of 460 volts and 4 kV motors either 4 kV or 4.16 kV with a nominal bus voltage of 4.3 kV. The author prefers 4.16 kV motor nameplate values for improved operating margins or less likelihood that the 480 voltage levels will be limited by how high the 4 kV system can operate. In the case of 4 kV nameplate motors, the limitation would be 110% of 4 kV or 4.4 kV, which would be the maximum continuous voltage rating of the motors. Figure 2.8 shows a RAT-fed 4 kV bus from Figure 1.23 (in Chapter 1) with the 230 kV system at its highest voltage of 241.5 kV and a lowest allowable winding ratio of 54.866. Tap B would provide a ratio of 54.826 as indicated in Figure 2.7 and would be the optimum choice. In regard to 460 volt nameplate motors, the limitation is 110% of 460, or 506 volts.

Volts/Hz withstand curves for generators and transformers are readily available from a number of manufacturers. The curves for transformers and generators will generally have the same slope, but generators start with a lower continuous rating of 105% and transformers at 110% (same as motors).

Because motor curves are not readily available, the bullets presented below were extrapolated from one of the more conservative volts/Hz curves for transformers and should reasonably represent motor withstand times as well:

- 134% = 0.1 minutes
- 131% = 0.2 minutes
- 126% = 2.0 minutes
- 120% = 5.0 minutes
- 116% = 20 minutes
- 114% = 50 minutes
- 111% = 100 minutes

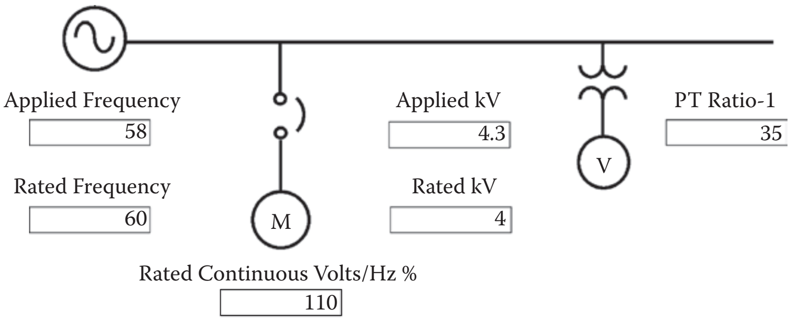
Motor, generator, and transformer voltage levels are limited by the level of magnetic flux that their core iron laminations can carry without overheating. The term *volts/Hz* is used to account for operation at reduced frequencies that lower the impedance and increase the excitation of the core iron. At 60 Hz, the percent volts/Hz corresponds directly to the overvoltage magnitude; that is, 115% overvoltage = 115% volts/Hz.

Figure 2.9, covers the procedure for calculating the impact of operating a 4 kV nameplate motor at a reduced frequency of 58 Hz. For reference purposes, the maximum bus and potential transformer secondary voltages at 60 Hz are determined to be 4.4 kV and 125.7 volts, respectively. A base volts/Hz ratio is calculated by dividing the rated or nameplate kV by the rated frequency. An applied volts/Hz ratio is then determined by dividing the applied kV by the applied frequency. The applied volts/Hz percentage can be calculated by dividing the applied ratio by the base ratio and multiplying by 100. In this example, the motor's maximum continuous volts/Hz rating of 110% is exceeded with a calculated percentage of 111% even though the 60 Hz maximum rated voltage of 4.4 kV is greater than the applied voltage of 4.3 kV. This is because the applied frequency of 58 Hz reduces the impedance of the stator windings, which increases the ampere turns and resulting magnetic flux in the stator core iron laminations.

2.3 Conductor Parameters

The next step for performing electrical studies usually involves determining the ampere ratings and impedance data of the associated electrical conductors.

In general, smaller conductors are mostly resistive in nature. As the size of the conductor increases (geometrical mean radius, or GMR), the inductive



$$Max.\ rated\ kV = \frac{\%\ Rated\ volts/Hz}{100} \times Rated\ kV \qquad \boxed{4.4}$$

$$Max.\ rated\ sec.\ Volts = \frac{Max.\ Rated\ kV \times 10^3}{PT\ ratio} \qquad \boxed{125.714}$$

$$Base\ volts/Hz\ ratio = \frac{kV\ rated}{Hz\ rated}$$

$$Applied\ volts/Hz\ ratio = \frac{kV\ applied}{Hz\ applied}$$

$$Applied\ volts/Hz\ \% = \frac{Applied\ ratio}{Base\ ratio} \times 100 \qquad \boxed{111.206}$$

$$Applied\ sec.\ volts = \frac{Applied\ kV \times 10^3}{PT\ ratio} \qquad \boxed{122.857}$$

Notes:
Useful for assessing motor operation at abnormal voltages or frequency.

FIGURE 2.9
Motor Volts/Hz Withstands

reactance reduces slightly and the conductor resistance reduces more dramatically. The inductive reactance reduces because of the effect of annular current flow (eddy currents) in the extra conducting material near the skin effect region or boundary that produces a counter flux resulting in a lowered self-flux opposition voltage as illustrated in Figure 2.10. Somewhere around medium size, the conductor resistance will equal the inductive reactance, and larger conductors will be mostly inductive in nature.

2.3.1 Buses

Generally speaking, copper and aluminum bus ampacities are a function of cooling, the cross-sectional areas, and the purity of the metals used to fabricate the bus bars. The calculation in Figure 2.11 is sometimes utilized in

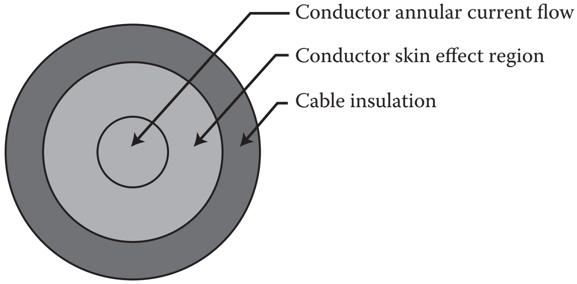


FIGURE 2.10
Conductor Radius and Inductance

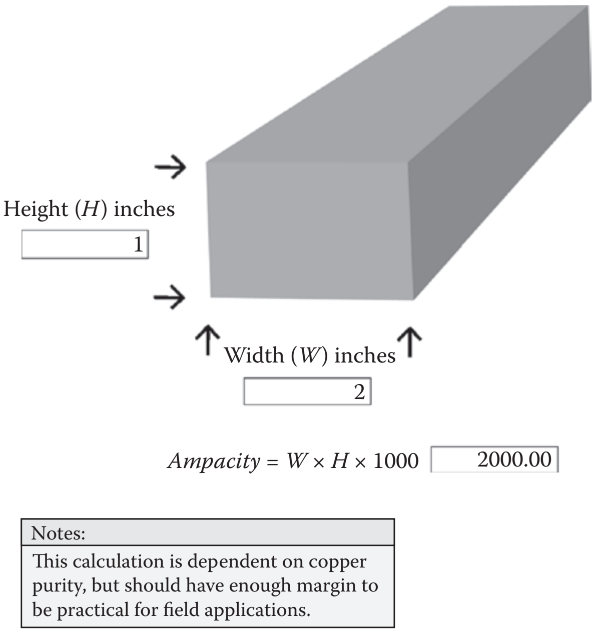


FIGURE 2.11
Copper Bus Ampacity

plants for the construction of copper bus bar jumpers and allows for a 30°C rise above ambient temperatures with the calculated current flowing. This calculation is conservative and has more than ample margin because the standards for buses allow for a much greater temperature rise.

The manufacturer of the busway normally provides the ampacity and impedance parameters for a specific design. Figure 2.12 shows the resistance and inductive reactance values for a 500-foot run of 2000 amp low voltage copper busway (480 volt applications) manufactured by the Square D Company. The resistance value assumes a conductor temperature of 80°C.

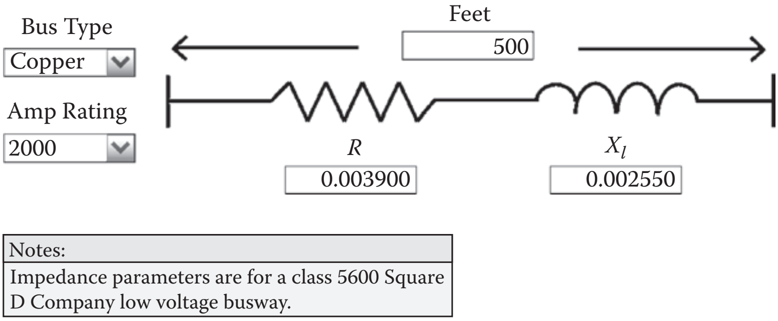


FIGURE 2.12
Low Voltage Busway

2.3.2 Insulated Cable

In general, cable ampere ratings are a function of the amount of copper, the temperature rating of the insulation, and the design of the raceway system. Although specific ampacity values can be obtained from the manufacturer, tables in the National Electrical Code (NEC) are commonly used to determine the ampacity for a particular design. Cable impedance data can be furnished by the manufacturer or taken directly from tables provided in IEEE Standard 141.

Figures 2.13 and 2.14 present the ampere rating and impedance parameters for a 500-foot run of 1000 kcm copper-insulated 90°C low voltage cable (480 volt applications) installed in magnetic and nonmagnetic conduit, respectively. By comparing the resistance values, it can be seen that the resistance is higher with magnetic conduit due to eddy current watt losses in the rigid conduit. Because most of the eddy current heating takes place in the conduit, the cable ampere rating is not impacted. The reactance values are also a little higher with magnetic conduit because the magnetic flux is attracted to the conduit, which results in a weaker subtractive effect from

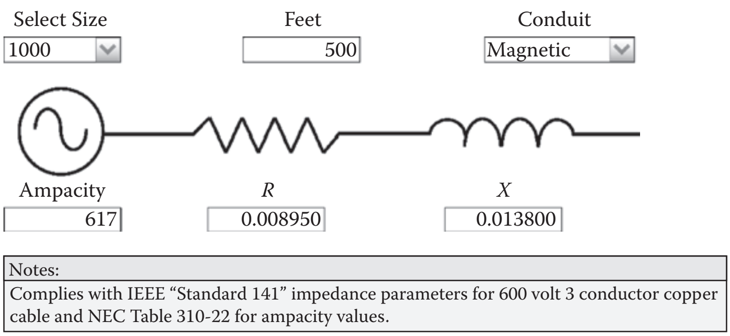


FIGURE 2.13
Low Voltage Cable in Magnetic Conduit

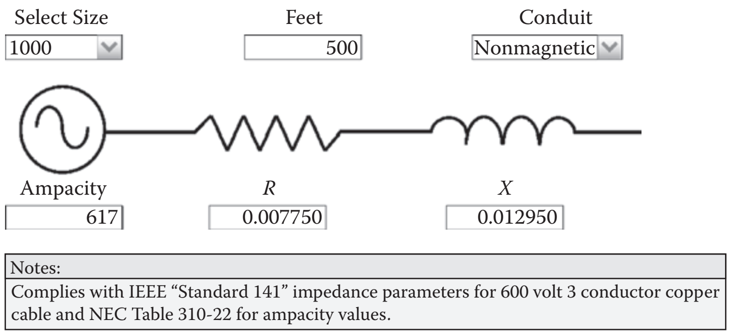


FIGURE 2.14
Low Voltage Cable in Nonmagnetic Conduit

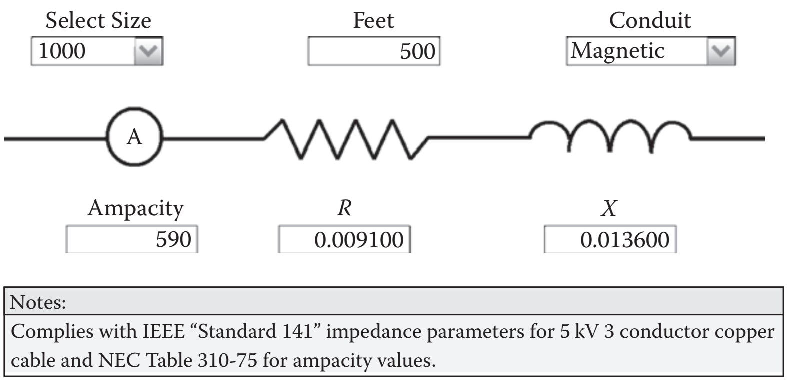


FIGURE 2.15
Medium Voltage 5 kV Cable in Magnetic Conduit

the other phases and increased self flux. Three conductors in one conduit are assumed for determining the ampacity, and a conductor temperature of 75°C is assumed for the conductor resistance values. More than three phase conductors in one conduit will require a reduced ampere rating because of the heat transfer from the other conductors; this is covered in the NEC. In somewhat balanced systems without significant harmonic content, the neutral conductor does not need to be considered in the derating. The ampacity values comply with NEC Table 310-22, and the impedance parameters are in agreement with IEEE Standard 141. The cable reactance values are higher than the busway inductive reactance shown in Figure 2.12, even though the busway spacing between phases is greater, because of the higher ampacities and geometries of the bus bars.

Figure 2.15 the presents the ampacity and impedance parameters for a 500-foot run of 5 kV 1000 kcm copper-insulated 90°C medium voltage cable (4 kV applications) installed in a magnetic conduit. Three conductors in one conduit are assumed for determining the ampacity and a conductor

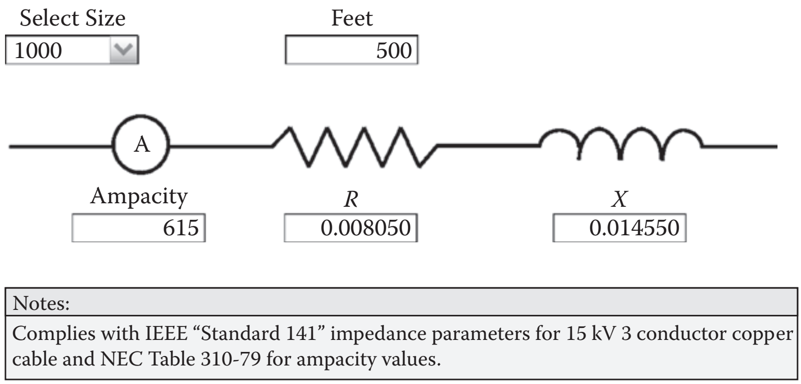


FIGURE 2.16
Medium Voltage 15 kV Cable in Nonmagnetic Conduit in Earth

temperature of 75°C is assumed for the conductor resistance value. The ampacity value complies with NEC Table 310-75 and the impedance parameters are in agreement with IEEE Standard 141. The resistance is higher due to the conduit eddy current watt loss.

Figure 2.16 provides the ampacity and impedance parameters for a 500-foot run of 15 kV 1000 kcm copper-insulated 90°C medium voltage cable installed in underground nonmagnetic conduit. Three conductors in one conduit and a soil thermal resistivity (RHO) of 90 are assumed for determining the ampacity, and a conductor temperature of 75°C is assumed for the conductor resistance value. The ampacity value complies with NEC Table 310-79, and the impedance parameters are in agreement with IEEE Standard 141. The inductance is higher than the 5 kV cable as a result of the increased spacing caused by the thicker 15 kV insulation, which overrides the magnetic conduit effect in the 4 kV cable. The ampacity is higher because the ground or earth acts as a heat sink and drains heat away from the cable.

2.3.3 Overhead Aluminum Conductor Steel Reinforced (ACSR) Cable

The ampacity and impedance values for overhead ACSR cables are provided in the *Westinghouse Transmission and Distribution Reference Book* and in other publications. Phase conductor spacing impacts the inductive reactance values. The magnetic self-flux that links with the conductor to cause the opposition voltage or inductive effect increases when the spacing is greater because the subtractive magnetic fluxes from the other phases have a weaker effect. If all three phase conductors could occupy exactly the same position or location, the inductive reactance would be zero because the vector sum of all three magnetic fluxes would be zero. This, of course, is not possible because the phases must be insulated from each other to prevent short circuit currents from flowing. This is illustrated in Figure 2.17 where

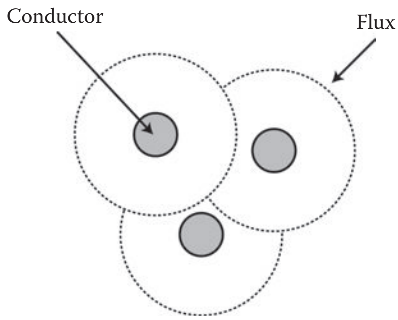


FIGURE 2.17
Spacing Impact on Inductance

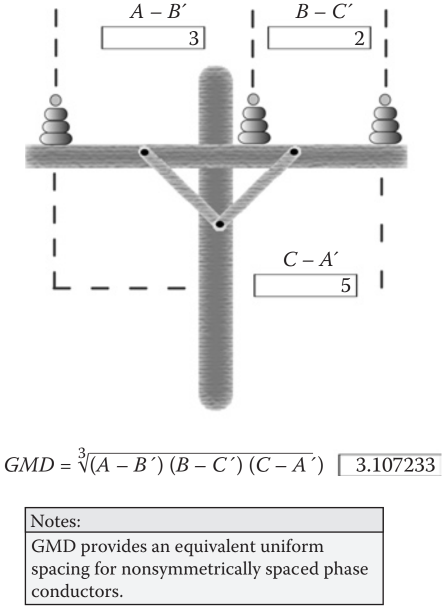
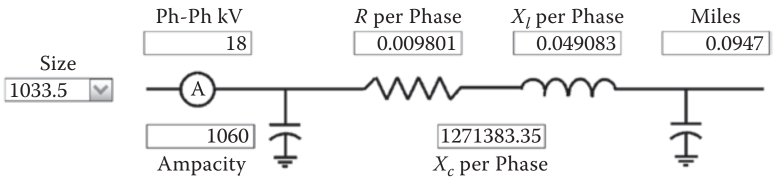


FIGURE 2.18
Equivalent Symmetrical Conductor Spacing

the overlapping flux gradient from other phases subtracts from the self flux originating from each conductor. Consequently, to more accurately determine the impedance values, the spacing between phases must be known. Usually this spacing is not symmetrical, and the unbalanced spacing must first be converted to an equivalent uniform spacing or geometrical mean distance (GMD) before the symmetrical spacing parameters provided in the references can be applied. Figure 2.18 illustrates an equivalent uniform spacing of 3.1 feet for three-phase conductors that are separated by 2, 3, and 5 feet, respectively.



Assumed Equivalent Spacing between Phases
0–1.9 kV = 1 ft.
2.0–7.5 kV = 2 ft.
7.6–29.9 kV = 3 ft.
30–75 kV = 6 ft.
75.1–99.9 kV = 9 ft.
100–199.9 kV = 12 ft.
200–299.9 kV = 18 ft.
300–399.9 kV = 24 ft.
400–599.9 kV = 36 ft.
≥ 600 kV = 48 ft.

Notes:
When available, 26 strand conductors were selected for the tabulation. Conductor resistance is given at 50 degrees C (approx. 75% capacity). See *Westinghouse Transmission and Distribution Reference Book* under characteristics of aerial lines for further information.

FIGURE 2.19
18 kV 1033.5 ACSR 3-Foot Spacing

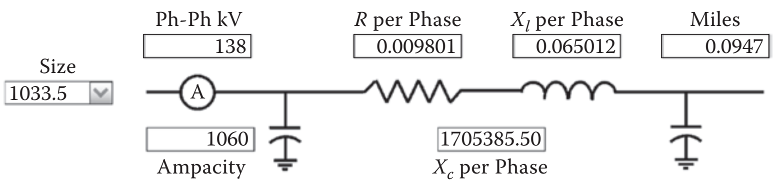


FIGURE 2.20
138 kV 1033.5 ACSR 12-Foot Spacing

Figures 2.19 and 2.20 show the impedance parameters for 18 kV (3-foot) conductor spacing and 138 kV (12-foot) conductor spacing, respectively. The actual spacing may differ significantly based on local weather and other environmental conditions; distance between spans; and concerns over galloping conductors, pole or tower support details, and margins preferred by the local utility. However, the effects are linear, and the actual reactance values can be extrapolated from reactance values associated with greater and lesser spacing. Although shown in miles, the line distance is equivalent to 500 feet for comparison to the other conductors already discussed. Comparing Figures 2.19 and 2.20, you will find that the resistance and ampacity values are the same, but the inductive and capacitive reactance values are higher for the 138 kV overhead cables due to the increased spacing between conductors. As mentioned before, increasing the spacing weakens the subtractive flux from the other phases which increases the self flux and inductance. The capacitive reactance increases because the distance between plates increases which reduces the microfarad value.

2.4 Study Accuracy

At this point in the chapter, we have addressed the preliminary data gathering, conversions, transformer tap optimization, and conductor parameters required for studies and can now proceed with the actual procedures for voltage, power transfer, and short circuit calculations. Calculations require only a precision that is practical for the particular application. Most calculations do not consider the exciting current associated with transformers or stray capacitance. Some calculations consider only the reactive and not the resistive components. Many procedures assume nominal magnitudes for voltages and other parameters and not actual values that may be in play prior to or during electrical system faults and disturbances. However, experience has shown that the calculation methods presented in this chapter and throughout the book have enough precision to be practical for the intended applications.

2.5 Voltage Studies

2.5.1 Bus Voltage Drop

Figure 2.21 provides a procedure for calculating bus voltage drops for balanced loads. First, the circuit MVA is converted to amps using the standard three-phase power formula. Next the impedance parameters (R and X) for the total circuit are calculated. Then the portion of R and X that is associated with the load only is determined. Finally, the sum of the resistive and reactive voltage drops at the load are calculated and then multiplied by the square root of 3 or 1.732 for conversion from a phase-to-neutral to a phase-to-phase voltage magnitude. In this example, because of the source impedance, the voltage at the bus is reduced from 4.3 kV to 3.8 kV. The power factor or angle will impact the results of the calculation.

2.5.2 Line Voltage Drop

Figure 2.22 provides a similar procedure for calculating line voltage drops for balanced loads. First the total circuit R and X is determined. Then the

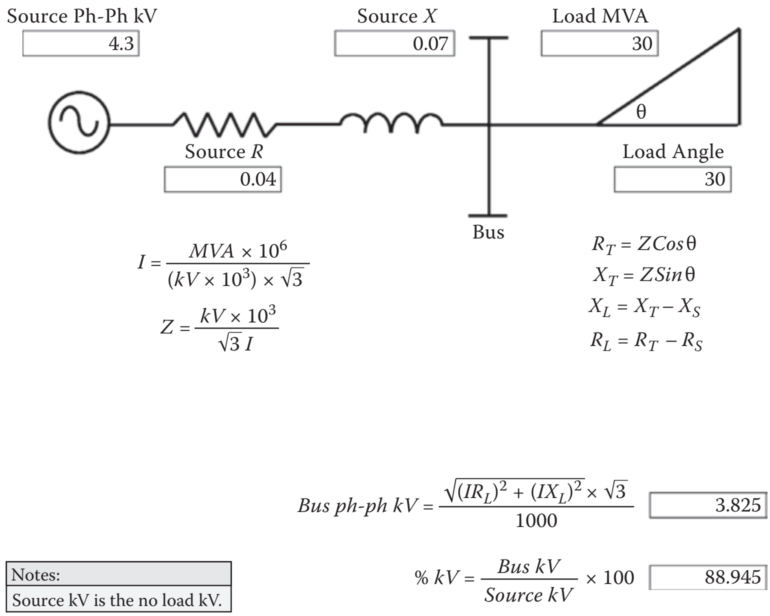


FIGURE 2.21
Bus Voltage Drop

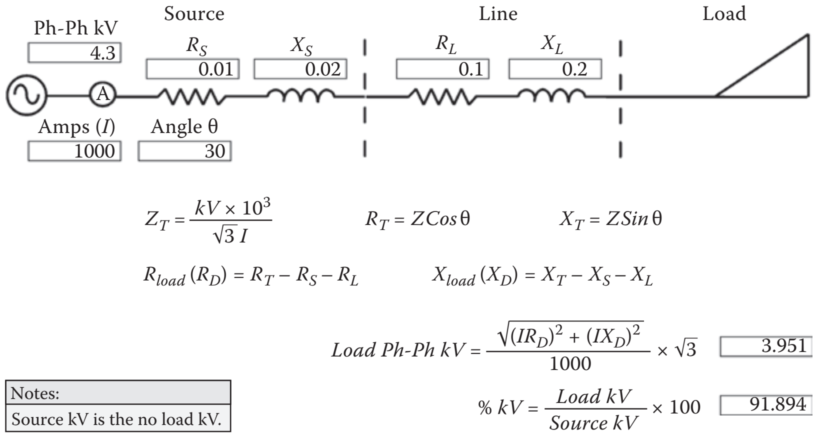
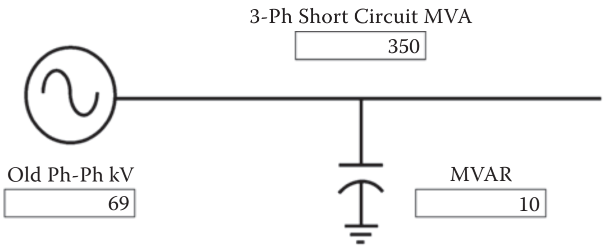


FIGURE 2.22
Line Voltage Drop

load R and X is derived. Finally, the sum of the resistive and reactive voltage drops at the load are calculated and then multiplied by the square root of 3 or 1.732 for conversion from a phase-to-neutral to a phase-to-phase voltage magnitude. As you can see, the voltage at the load is reduced from 4.3 kV to 3.95 kV due to the source and cable impedance.



$$\%\ Voltage\ rise\ (V_R) = \frac{100 \times MVAR}{MVA} \quad \boxed{2.857}$$

$$New\ kV = \left[\frac{V_R}{100} \times Old\ kV\right] + Old\ kV \quad \boxed{70.971}$$

Notes:
Approximates the voltage rise on a three-phase system with the addition of a three-phase capacitor bank.

FIGURE 2.23
Capacitive Voltage Rise

2.5.3 Capacitive Voltage Rise

Figure 2.23 covers how to approximate the effect that three-phase balanced capacitance has on voltage levels. If the total circuit capacitance in megavars (MVAR) times 100 is divided by the short circuit duty in MVA, the result will yield the percent voltage rise of the circuit. The voltage rise could be caused by installed capacitor banks or by the capacitance of long transmission lines that are lightly loaded. In this example, the addition of a 10 MVAR bank will increase the voltage from 69 to almost 71 kV.

2.5.4 Collapsing Delta

Figure 2.24 discloses how to calculate the unfaulted phase-to-phase voltages if the faulted phase-to-phase voltage is known. This is useful for unbalanced voltage studies and for testing some phase-to-phase impedance relay elements. In this case, if the C-B voltage is reduced to 50 kV, the unfaulted phase-to-phase voltages will be reduced to 201 kV.

2.6 Power Transfer Calculations

Figure 2.25 deals with the basic power transfer equations for three-phase watts and vars caused by voltage and angular differences or delta (power

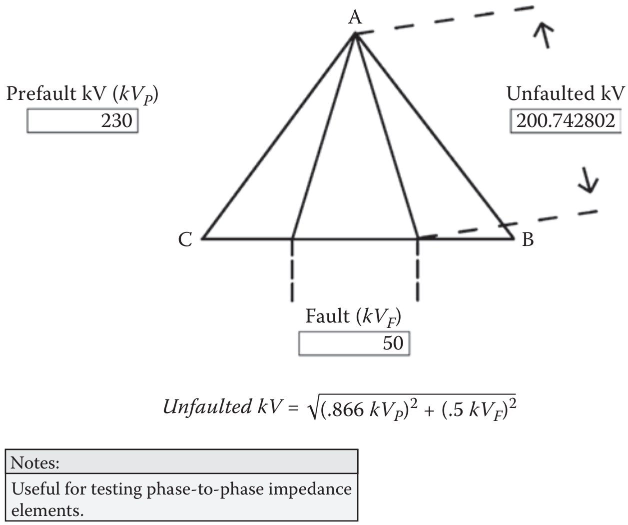


FIGURE 2.24
Collapsing Delta

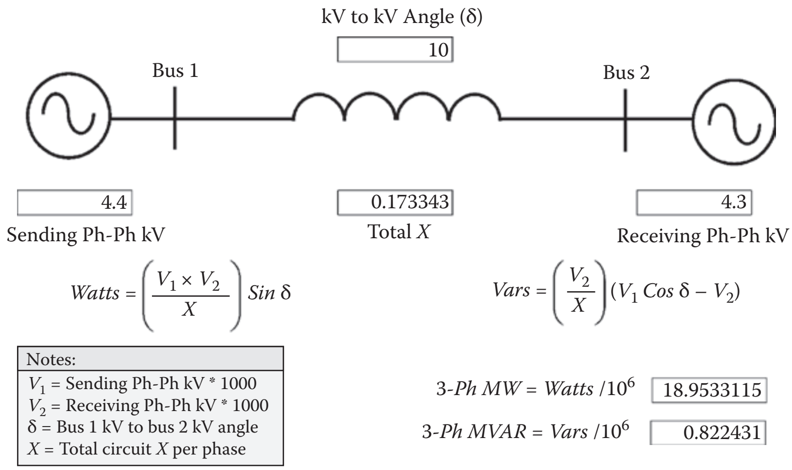


FIGURE 2.25
Power Transfer Equations

angle) between two different points on an electrical system and the limiting affects of the total circuit inductive reactance ohms. Angle in this case refers to angular differences between the voltage on bus 1 versus the voltage on bus 2. If phase-to-phase voltages are used in the equations, the calculations yield three-phase watt and var magnitudes that will flow from one point to the other. In general, watts will flow from the leading to the lagging angle and vars will flow from the higher to the lower voltage system. In this example, a 10-degree angular delta between bus 1 and bus 2 causes 18.9 MW and 0.8 MVAR to flow from bus 1 to bus 2 when the buses are operated in parallel.

2.7 Two-Generator System

Figure 2.26 illustrates a two-generator system with identical turbines and generators. The right triangle in the first quadrant represents a typical system load that is resistive and inductive and series in nature. The current is the reference, and the voltage phasor falls into alignment with the hypotenuse or VA of the right triangle. If equal steam flows through each turbine and the field or excitation currents are the same, each generator would provide one-half the watt and one-half the var requirement of the system load. If the generator governors are on manual and steam flow is increased for machine A, it would feed a greater portion of the watt requirement, and the system frequency would increase if machine B did not back down. The increased steam flow in machine A would cause its power angle to increase (in the leading direction), which would put it in advance of machine B, allowing it to feed a greater portion of the load. If the generator automatic voltage regulators (AVR) are also on manual and excitation or field current is increased for machine A, it would feed a greater portion of the var requirement and the system voltage would increase if machine B did not back down on excitation. This is referred to as *boost vars*, and if the power factor was measured for generator A, it would show that the current was lagging the voltage by a greater amount. If the excitation for A is increased high enough, the total system var requirement would be fed by A and generator B would be at unity power factor. If the excitation for A is increased beyond that point, B would become a var load for A and the current in B would lead the voltage, resulting in *buck vars.* In this case, the right triangle for B would be inverted and shown in the fourth quadrant.

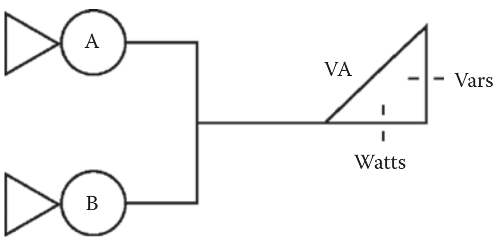


FIGURE 2.26
Two-Generator System

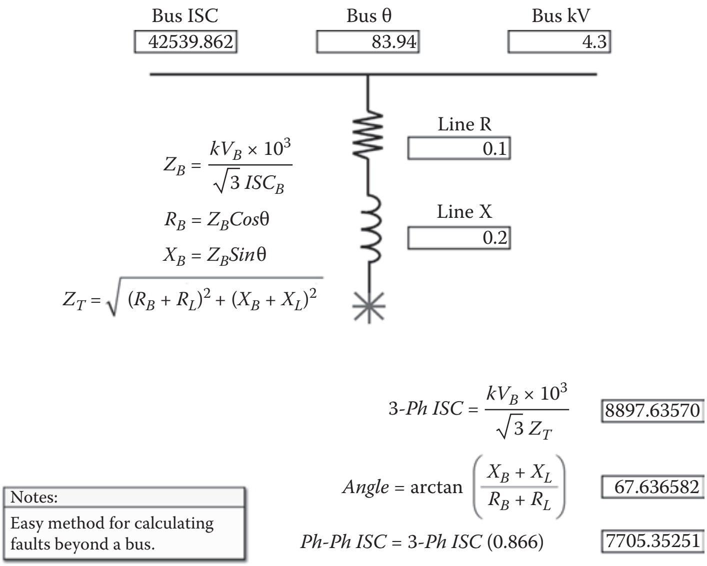


FIGURE 2.27
Short Circuit: No Transformer

2.8 Ohmic Short Circuit Calculations

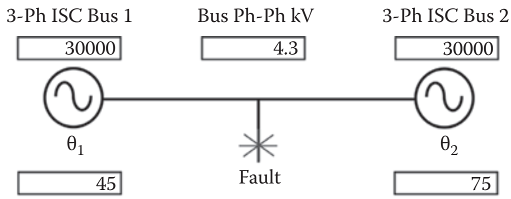
Short circuit calculations that do not involve transformation can easily be performed using ohmic values.

2.8.1 No Transformer

Figure 2.27 covers how three-phase short circuit current at the end of a line impedance can easily be determined if the short circuit duty at the source bus is known. The bus short circuit current is converted to R and X values that can be added to the line R and X, and then the total current at the end of the line can be determined by using three-phase Ohm's Law. The phase-to-phase short circuit current is normally equal to 86.6% of the three-phase value because the ratio of three-phase ohms to phase-to-phase ohms equals 1.732/2 or .866. three-phase ohms = (phase-to-phase E/1.732 I), and phase-to-phase ohms = (phase-to-phase E/2 I) because the return impedance of the second phase needs to be considered.

2.8.2 Parallel Sources

When two sources are operated in parallel, the short circuit contribution from each source needs to be added together to determine the total short circuit current. If the angles are the same, the new total current will simply



$$Z_1 = \frac{kV \times 10^3}{\sqrt{3}\, ISC_1} \qquad Z_2 = \frac{kV \times 10^3}{\sqrt{3}\, ISC_2}$$

$$R_1 = Z_1 Cos\theta_1 \qquad R_2 = Z_2 Cos\theta_2$$

$$X_1 = Z_1 Sin\theta_1 \qquad X_2 = Z_2 Sin\theta_2$$

$$G_1 = \frac{R_1}{R_1^2 + X_1^2} \qquad G_2 = \frac{R_2}{R_2^2 + X_2^2}$$

$$B_1 = \frac{X_1}{R_1^2 + X_1^2} \qquad B_2 = \frac{X_2}{R_2^2 + X_2^2}$$

$$Z_T = \frac{1}{\sqrt{(G_1 + G_2)^2 + (B_1 + B_2)^2}}$$

$$ISC_T = \frac{kV \times 10^3}{\sqrt{3}\, Z_T} \quad \boxed{57955.55}$$

$$\theta = \arctan \frac{B_1 + B_2}{G_1 + G_2} \quad \boxed{60}$$

Notes:
Common applications are calculating the total short circuit current when two buses are operated in parallel and determining unit auxiliary transformer primary duty.

FIGURE 2.28
Short Circuit: Parallel Sources

be the algebraic sum of the two currents. However, if there are angular differences, a conductance, susceptance, and admittance method for solving parallel impedances can be applied to determine the total magnitude of the combined currents. Figure 2.28 presents a method of resolving the total short circuit current from two sources that have angular differences. Figure 2.29 shows the reverse process of subtracting out or removing a source with angular differences from the total value. In regard to generating stations, these calculations are particularly useful for determining high voltage switchyard short circuit currents when generating units are on and off line. They are also useful for determining the combined short circuit currents of the generator and GSUT at the UAT primary terminals.

2.9 The Per-Unit System

Whenever transformers are involved in a study, it is normally easier to use a percentage or per-unit approach for resolving problems because of the

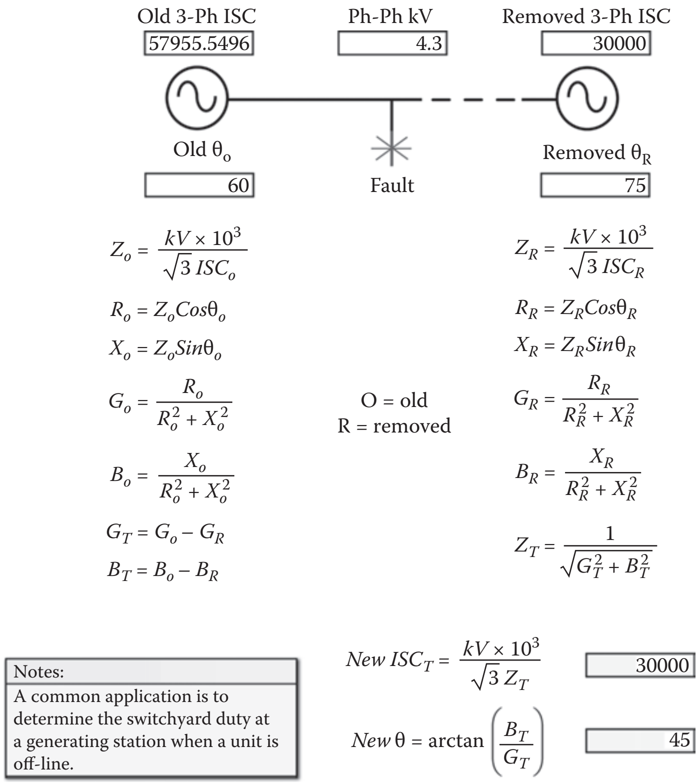


FIGURE 2.29
Short Circuit: Removing Parallel Sources

different voltages involved in the study. Because ohmic values depend on which side of the transformer (primary or secondary) you are looking at, transformer impedances are almost always expressed as a percentage. The per-unit value is simply the percentage divided by 100; for example, a 7% impedance transformer would have a per-unit impedance of .07. Because a transformer's primary MVA is equal to its secondary MVA, a percentage or per-unit system can be applied as long as the base values chosen for MVA, voltages, impedances, and currents are consistent. The base values are normally selected for convenience to be in agreement with apparatus nameplate values or with other data or studies that were previously performed. During the course of studies, it is often necessary to adjust values to a different base to be consistent with other data or to convert to other forms that are more convenient.

2.9.1 Basic Formulas

Although it is not always obvious, the basic formulas presented in Chapter 1 still apply when using the per-unit system. One complication is that 1.0 per unit could represent full load amps or some other parameter and because ones can easily drop out of formulas, the expressions may no longer be presented in a manner that is familiar to the reader. For example:

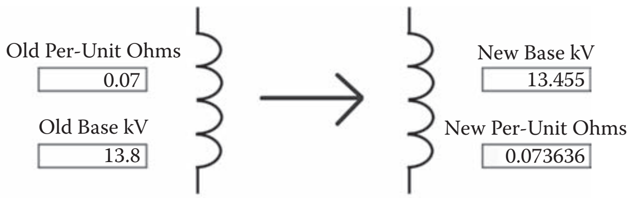
- Per unit (pu) amps = pu volts/pu Z
- Amps = pu amps × base amps; or shortcut method:
- Amps = base amps/pu Z

2.9.2 Corrected Voltage Base

The percent or per-unit impedance of transformers often needs to be adjusted for applied winding taps and actual applied voltages that are different than the nameplate base values. The nameplate will show the %Z at a specified MVA and winding tap. Normally, it would be specified at the OA (oil and air) or lower MVA rating and for the mid-tap winding voltage. If the applied voltage is different or the selected tap is different, the %Z self-cooled rating is usually adjusted or corrected for the differences. Figure 2.30 is used to adjust or correct a transformer's base per-unit impedance to a different winding tap. Figure 2.31 is the same calculation used again to convert the transformer's tap corrected base per-unit impedance to the actual applied or system voltage of 14 kV. Figure 2.32 combines both calculations into a single expression that corrects for both winding tap and applied voltage differences.

2.9.3 Per-Unit Z to Amps

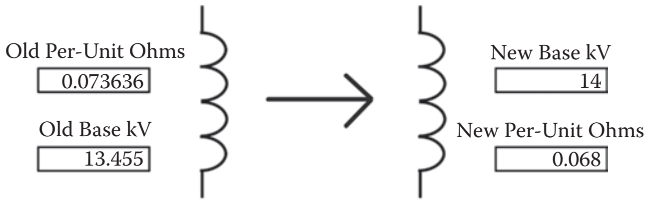
A transformer's infinite bus (unlimited supply) three-phase short circuit current can be calculated by dividing its rated three-phase current by its



$$New\ pu\ Ohms = \frac{(Old\ kV\ Base)^2}{(New\ kV\ Base)^2} \times Old\ pu\ Ohms$$

Notes:
Commonly used to adjust a transformer's pu Z to different taps and/or different system voltages.

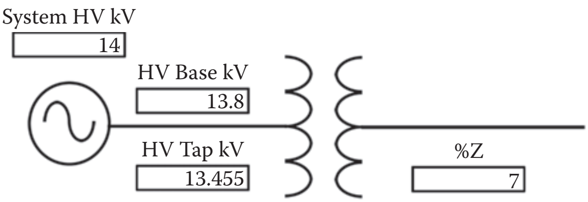
FIGURE 2.30
Transformer Winding Tap Correction



$$New\ pu\ Ohms = \frac{(Old\ kV\ Base)^2}{(New\ kV\ Base)^2} \times Old\ pu\ Ohms$$

Notes:
Commonly used to adjust a transformer's pu Z to different taps and/or different system voltages.

FIGURE 2.31
Transformer Applied Voltage Correction



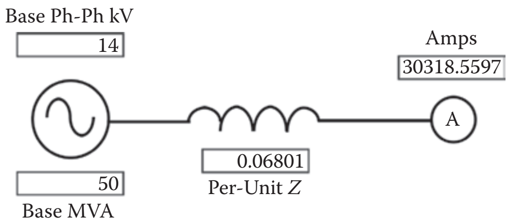
$$Corrected\ pu\ Z = \frac{HV\ Base\ kV^2}{HV\ Tap\ kV^2} \times \frac{HV\ Tap\ kV^2}{System\ kV^2} \times \frac{\%\ Z}{100} \quad \boxed{0.068014}$$

$$Corrected\ \%\ Z = Corrected\ pu\ Z \times 100 \quad \boxed{6.8014}$$

Notes:
Useful for adjusting a transformer's impedance to actual system and tap voltages. All input voltages should be either Ph-Ph or Ph-N, but not both.

FIGURE 2.32
Transformer Tap and Applied Voltage Correction

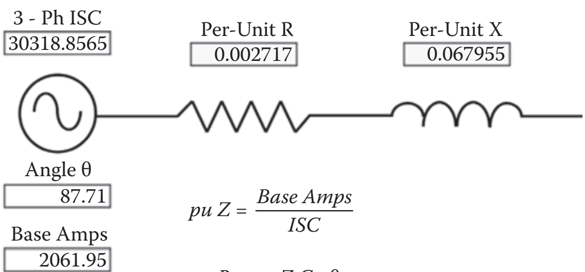
per-unit impedance, as shown in Figure 2.33. Using the primary kV base current provides the primary current for a secondary fault, and using the secondary kV base current provides the secondary current for the same fault. Figure 2.32 represents the transformer displayed in Figure 2.33; the calculation yields the infinite source three-phase secondary short circuit current on the 14 kV side and is probably within 90% or more of the actual value for faults near the secondary bushings or terminals. However, standard practice is to complete a more refined calculation that includes the source and line impedance to the short circuit location.



$$Base\ Amps = \frac{MVA \times 10^6}{\sqrt{3}\, kV \times 10^3} \qquad Amps = \frac{Base\ Amps}{pu\ Z}$$

Notes:
Commonly used to calculate a transformer's infinite or zero ohm source bus short circuit amps.

FIGURE 2.33
Per-Unit Z to Amps



$$pu\ Z = \frac{Base\ Amps}{ISC}$$

$$pu\ R = pu\ Z\ Cos\theta$$

$$pu\ X = pu\ Z\ Sin\theta$$

Notes:
Commonly used to convert short circuit current to pu R and X for further calculations.

FIGURE 2.34
Amps to Per-Unit R and X

2.9.4 Amps to Per-Unit R and X

Figure 2.34 illustrates how to calculate the per-unit R and X angle if the short circuit angle is known, and Figure 2.35 covers how to determine the balanced three-phase short circuit current if the per-unit R and X are given.

2.9.5 New MVA Base

Occasionally, MVA base values need to be adjusted to accommodate different apparatus or data from another study. Figure 2.36 shows how to adjust per-unit

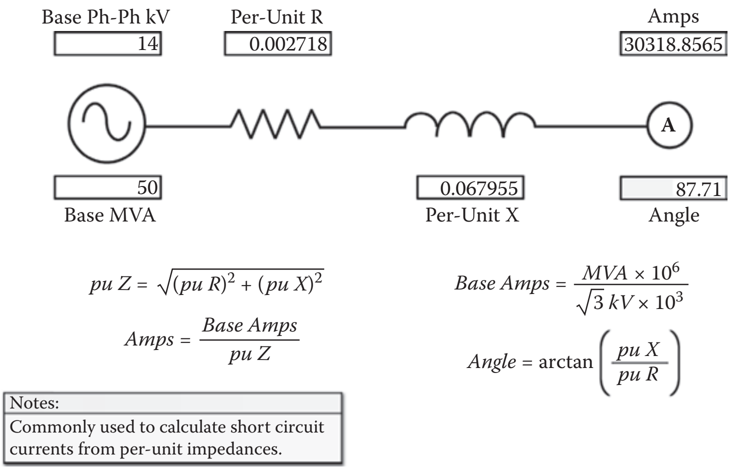


FIGURE 2.35
Per-Unit R and X to Amps

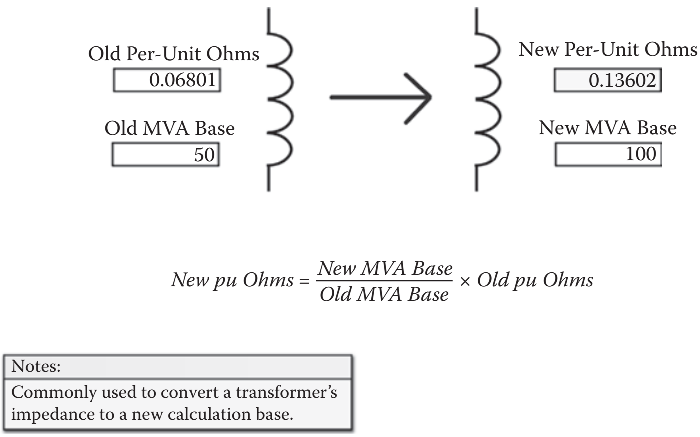


FIGURE 2.36
New MVA Base

ohms from a 50 to a 100 MVA base. The impedance does not need to be corrected for single-phase transformers that are used in three-phase banks. Although the combined MVA is higher, the base current does not change and "three-phase ohms" equal "phase-neutral ohms." A 7% single-phase 10 MVA transformer also has a 7% impedance when used in a three-phase 30 MVA bank.

2.9.6 Per Unit to Ohms

At some point in your study, per-unit ohms may need to be converted to actual ohms for protective relay or other applications. This can be accomplished

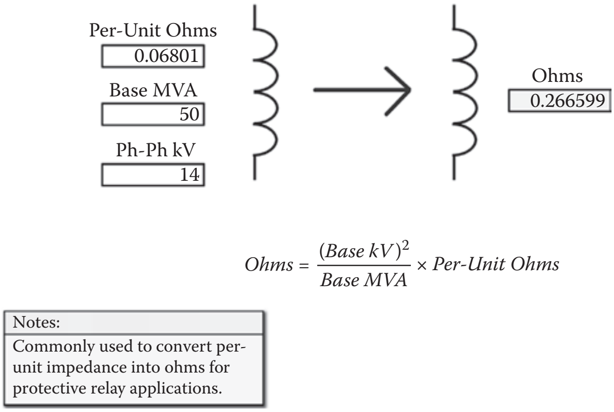


FIGURE 2.37
Per Unit to Ohms

using the formula presented in Figure 2.37. The inverse calculation is shown in Figure 2.38.

2.9.7 Amps to Per-Unit Z

Converting amps to per-unit Z is useful for some applications, as shown in Figure 2.39; for example, dividing a motor's full load amps (FLA) by the locked rotor current (LRA) provides the per-unit impedance of the motor.

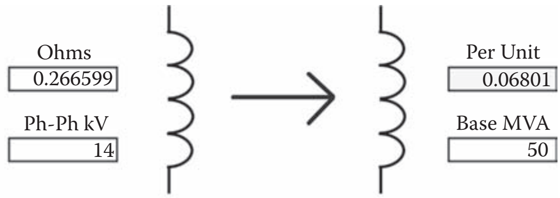
2.10 Per-Unit Short Circuit Calculations

2.10.1 Transformer Short Circuits

Figures 2.40, 2.41, and 2.42 provide procedures for calculating short circuit currents for the three most common transformer configurations. By comparing the procedures in all three figures, it can be seen that they are the same for determining secondary three-phase and phase-to-phase short circuit currents and the results are the same. Additionally, the primary currents for secondary three-phase faults are the same in all cases. However, the wye-delta and delta-wye winding configurations cause the current to increase in one of the primary phases for secondary phase-to-phase faults. The delta-wye grounded transformer can also deliver ground fault current.

2.10.2 Transformer Three-Phase and Phase-to-Phase Fault Procedures

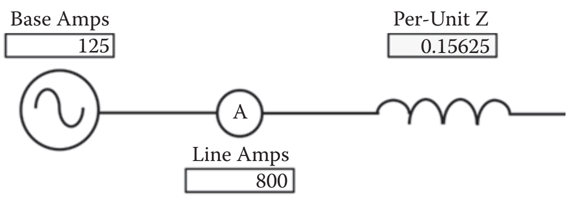
Let's start with the delta-delta transformer in Figure 2.40 because the short circuit currents are easier to calculate. First, an MVA base is selected; using



$$Per\ Unit = \frac{Base\ MVA}{(Base\ kV)^2} \times Ohms$$

Notes:
Ohms should be provided at the same kV level as the Base kV.

FIGURE 2.38
Ohms to Per Unit



$$Per\text{-}Unit\ Z = \frac{Base\ Amps}{Line\ Amps}$$

Notes:
Useful for converting motor LRA to per-unit Z.

FIGURE 2.39
Amps to Per-Unit Z

the transformer MVA as the base avoids additional conversions. Next, the source short circuit current is converted to R and X and then to per-unit values. The transformer percent impedance is also converted to per-unit R and X values using the X/R ratio, and finally the line R and X is converted to per-unit R and X values. The three-phase secondary fault current is the secondary base current divided by the total per-unit impedance and the angle is the arc-tangent of the per-unit X/R ratio. Dividing the secondary short circuit current by the phase-to-phase ratio will yield the primary current. The secondary phase-to-phase fault current magnitude is 86.6% of the three-phase value and in this configuration, the secondary current divided

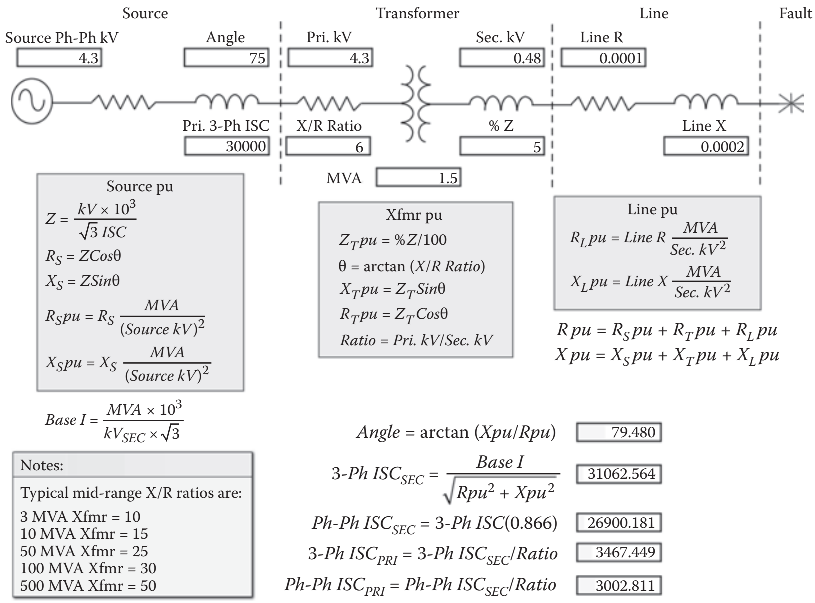


FIGURE 2.40
Delta-Delta Transformer Short Circuit

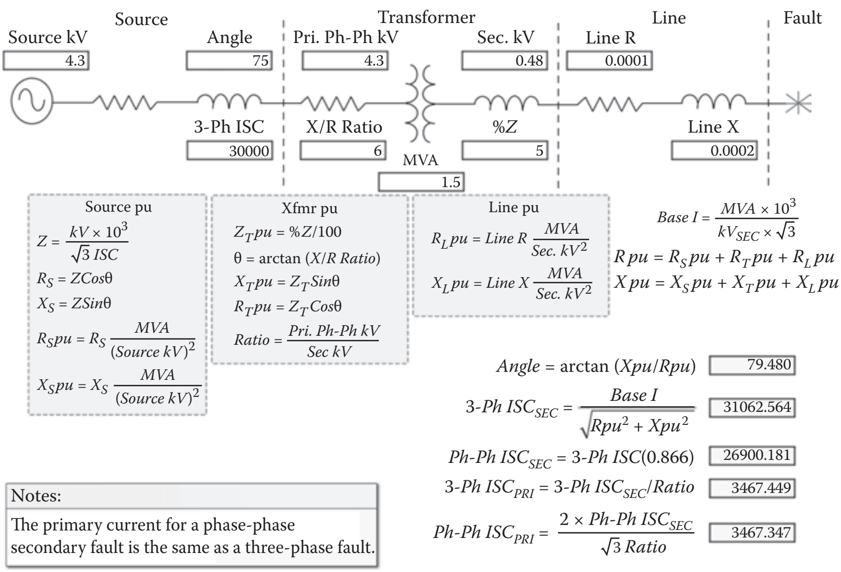


FIGURE 2.41
Wye-Delta Transformer Short Circuit

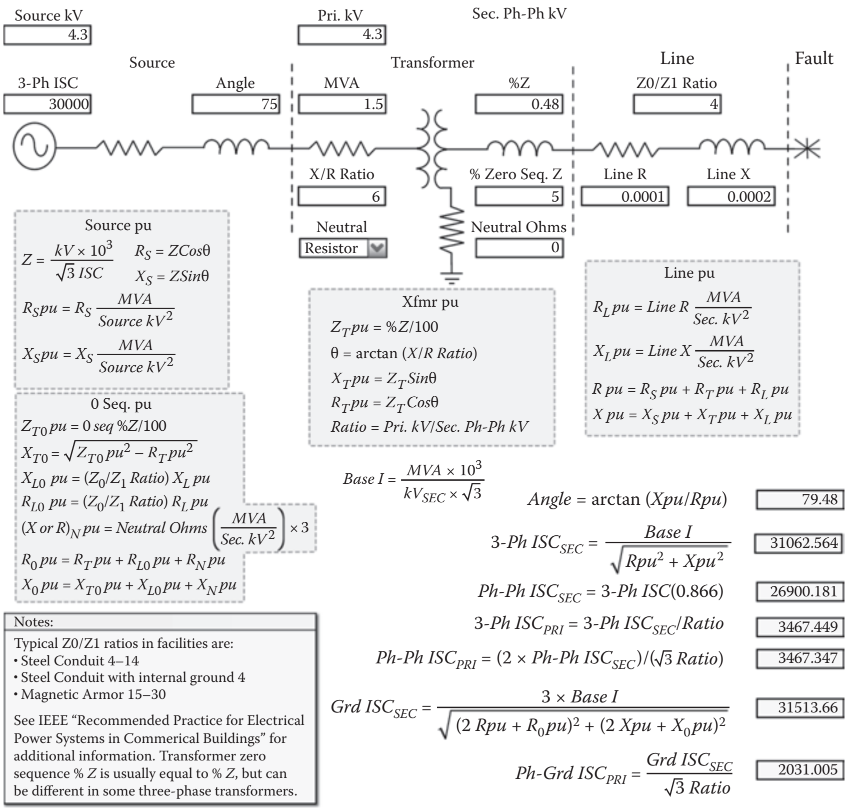


FIGURE 2.42
Delta-Wye Transformer Short Circuit

by the ratio yields the primary current. Figure 2.40 also provides typical X/R ratios if specific transformer X/R ratios are not available.

For the wye-delta and the delta wye transformers in Figures 2.41 and 2.42, the calculating procedures are identical with Figure 2.40 except for primary currents for phase-to-phase secondary faults. In both cases, one of the primary phases sees it the same as a three-phase 100% fault even though it is really an 86.6% phase-to-phase fault. The delta-wye grounded configuration can also deliver ground fault current.

Let's take a look at the phase-to-phase current flow for the delta-wye transformer in Figure 2.42 first because it is simpler. Figure 2.43 illustrates current flow for an A-B fault. As you can see, B phase has a greater primary current due to the contribution from the other two phases. Figure 2.44 shows the phasor relationships.

Figure 2.45 illustrates the current flow for the wye-delta transformer in Figure 2.41 for an A-B secondary fault. The current flow in this case is much more complicated than the delta-wye transformer configuration. In addition

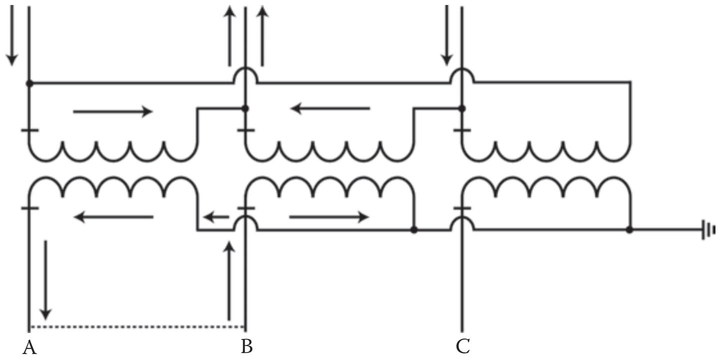


FIGURE 2.43
Delta-Wye Transformer Phase-to-Phase Fault Currents

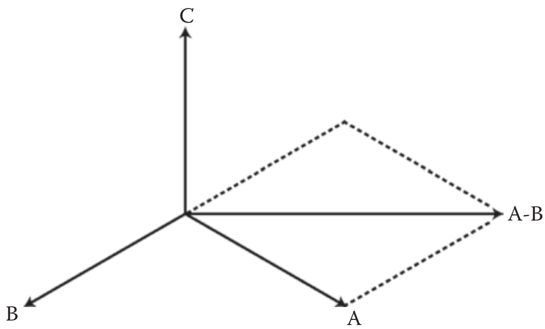


FIGURE 2.44
Delta-Wye Transformer Phase-to-Phase Phasors

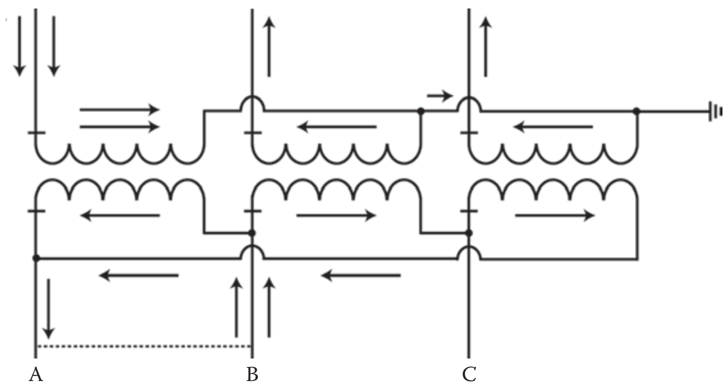


FIGURE 2.45
Wye-Delta Transformer Phase-to-Phase Fault Currents

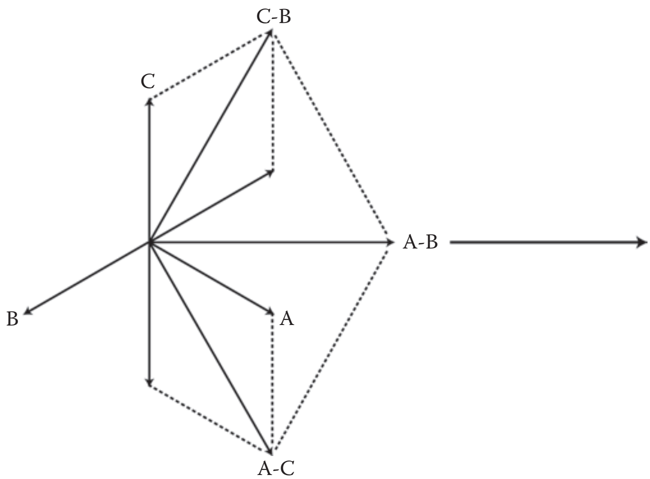


FIGURE 2.46
Wye-Delta Transformer Phase-to-Phase Phasors

to the A-B winding, the B-C winding in series with the C-A winding is in parallel with the fault and also provides fault current to the A-B fault, which increases the primary current in A phase.

Figure 2.46 illustrates the phasor relationships. The B-C and C-A vectors are reversed because current flows in each secondary winding are in on polarity instead of out on polarity. Two A-B vectors are shown, one for each winding configuration that feeds the fault.

2.10.3 Sequence Impedances

Calculating ground faults and analyzing unbalanced conditions for three-phase systems can be quite complex. In 1918, Dr. C. L. Fortescue presented a paper at an American Institute of Electrical Engineers (AIEE) convention in Atlantic City, New Jersey, on a method for analyzing three-phase systems using positive, negative, and zero sequence phasors (symmetrical components). Positive sequence (1) represents normal balanced conditions and rotation; negative sequence (2) represents unbalanced currents in the armature or stators of rotating electrical apparatus that produce a reverse rotation current in the rotors or fields of generators and motors; and zero sequence (0) represents ground fault currents without rotation. Consequently, many in the industry will refer to balanced events as positive phase sequence, phase-to-phase events as negative phase sequence, and ground faults as zero phase sequence. Although the foregoing is really an oversimplification of symmetrical components, ground fault currents through delta-wye transformers can be readily calculated with a procedure that utilizes positive, negative, and zero sequence impedances. Figure 2.47 illustrates the sequence

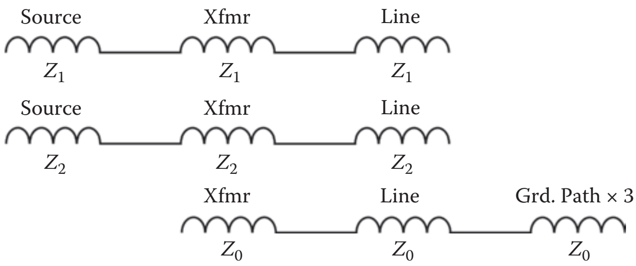


FIGURE 2.47
Normal Delta-Wye Ground Fault Sequence Impedances

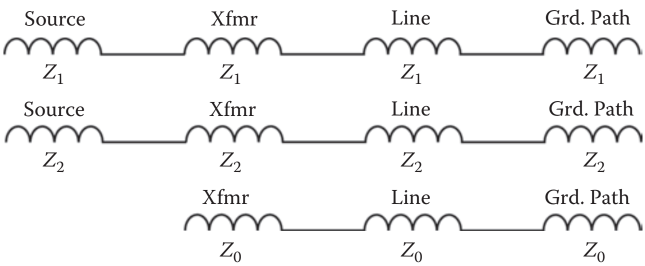


FIGURE 2.48
Equivalent Delta-Wye Ground Fault Sequence Impedances

impedances (for simplification, it does not show the resistance) that will be utilized. Figure 2.48, for illustrative purposes, is mathematically the same, but applies the ground return path impedance to each sequence leg, negating the need to multiply the ground return path impedance by 3.

2.10.4 Transformer Ground Fault Procedure

Referring to Figures 2.42 and 2.47, basically the base current is multiplied by 3 and then divided by the sum of the positive, negative, and zero sequence per-unit impedances. The positive sequence per-unit impedances are derived from the source impedance, percent impedance of the transformer, and the line ohmic values to the point of the fault. The positive and negative sequence magnitudes are considered equal to each other, and doubling the positive sequence impedances will account for both in the equation. The zero sequence impedance includes the transformer zero sequence %Z (usually considered the same as the %Z of the transformer but can be lower in three-phase core form transformers), line and ground return path impedances and any limiting impedance in the neutral. Because the base current is multiplied by 3, any impedance introduced in the transformer neutral and in the ground return path has to be multiplied by 3 to balance out the equation.

As you can see in Figure 2.42, the ground fault magnitude exceeds the three-phase fault value because the zero sequence impedance does not include the source impedance. However, the zero sequence impedance increases faster than the positive sequence impedance as the distance from the transformer to the ground fault location increases; therefore, the three-phase short circuit current often exceeds the phase-to-ground fault current at the secondary side circuit breaker. Transformers and generators are generally not designed to handle large close in ground fault currents that are above the three-phase value; consequently, some transformers are equipped with neutral reactors to limit the close in ground fault current, and generators are normally high impedance grounded to limit the ground current. Figure 2.42 also provides typical Z_0/Z_1 ratios for commercial and industrial facilities. The positive sequence impedances for cables and busways can be multiplied by a Z_0/Z_1 ratio to estimate the impedance for the line plus the ground return path (does not include transformer neutral-to-ground impedance). Because, the overall Z_0/Z_1 ratio can range from as little as 1 to as much as 50, precisely estimating the ratio is not practical because of the many variables in ground current return paths. Because of this, worst-case conditions are often assumed when making ground fault calculations for short circuit duty considerations. The suggested Z_0/Z_1 ratio of 4 assumes that the ground return path impedance equals the line impedance to the point of the fault and is the more conservative calculation.

Figure 2.49 shows a representation of the line impedance as 1 ohm and the ground return path as 1 ohm times 3. The overall zero sequence impedance for the line plus the return path equals 3 plus 1, or 4. Accordingly, in this case, the Z_0/Z_1 ratio equals 4. For Z_0/Z_1 ratios greater than 4, much of the circuit impedance is in the line itself due to the increased spacing between the line and the return path. In analyzing the Z_0/Z_1 ratios presented in Figure 2.42, the lowest Z_0/Z_1 ratio of 4 is assigned when a ground conductor is provided in the same conduit as the line conductors, reducing the spacing between

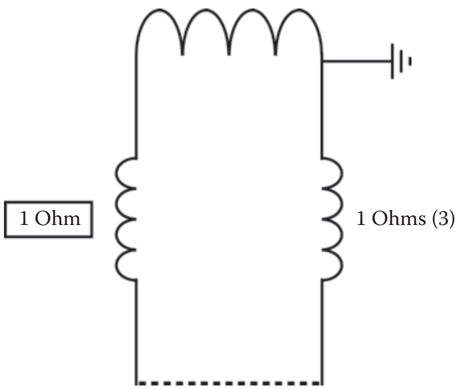


FIGURE 2.49
Z_0/Z_1 Ratio

the line and ground return path and the associated self flux and inductive reactance of each conductor.

2.10.5 Alternative Ground Fault Procedure

As a matter of interest, delta-wye ground fault current can also be determined without resorting to sequence impedances by applying more conventional methods without major difficulty for applications that do not involve parallel sources on the wye side. It is really a relatively simple circuit with current flows in only one of the three single-phase transformers that make up a three-phase bank. It can also be debated that this method is simpler, has fewer steps, and relies on conventional theory instead of a sequence impedance procedure that is contrary to actual basic theory. The sequence impedance method (which provides an equal result) advocates 3V0 and 3I0, which can be calculated but do not really exist, suggests that the ground fault current is higher at the transformer because the source impedance is not considered in the zero sequence path (which is not the real reason), and that the zero sequence impedance increases rapidly because it is multiplied by 3 (which is also not the real reason). Figure 2.50 illustrates the same delta-wye grounded transformer with an identical C-phase secondary ground fault, but in this case, the actual current paths and impedances will be utilized.

As you can see by the current flow, the ground fault looks like a phase-to-phase fault to the source. Consequently, the phase source impedance is multiplied by 2 to consider the impedance from two different phases. Twice the source impedance is then reflected to the secondary or 480 side (calculation for step-down transformer only). The transformer ohms are also determined on the 480 volt side, and the ground return path impedance is assumed to equal the line impedance (Z_0/Z_1 ratio of 4). Therefore, doubling the line impedance also accounts for the return path impedance. Finally, the total neutral or ground current can now be determined by dividing the phase-to-neutral voltage by the total impedance (including the neutral-to-ground impedance if applicable). If you compare the ground fault current magnitudes in Figure 2.50 to those in Figure 2.42, you will find that they are identical. The ground fault current exceeds the three-phase value near the transformer because the ratio is higher (higher secondary current) because phase-to-neutral instead of phase-to-phase voltages are utilized in the calculation. The ground fault impedance increases faster than the three-phase impedance because the three-phase calculation does not need to consider the return path impedance. The ground fault angle can now easily be determined by the arc-tangent of the X/R ratio.

2.10.6 Generator Three-Phase Short Circuits

Figure 2.51 presents the three 3-phase short circuit levels for generators. Basically, the highest level of current occurs during the first few cycles and is

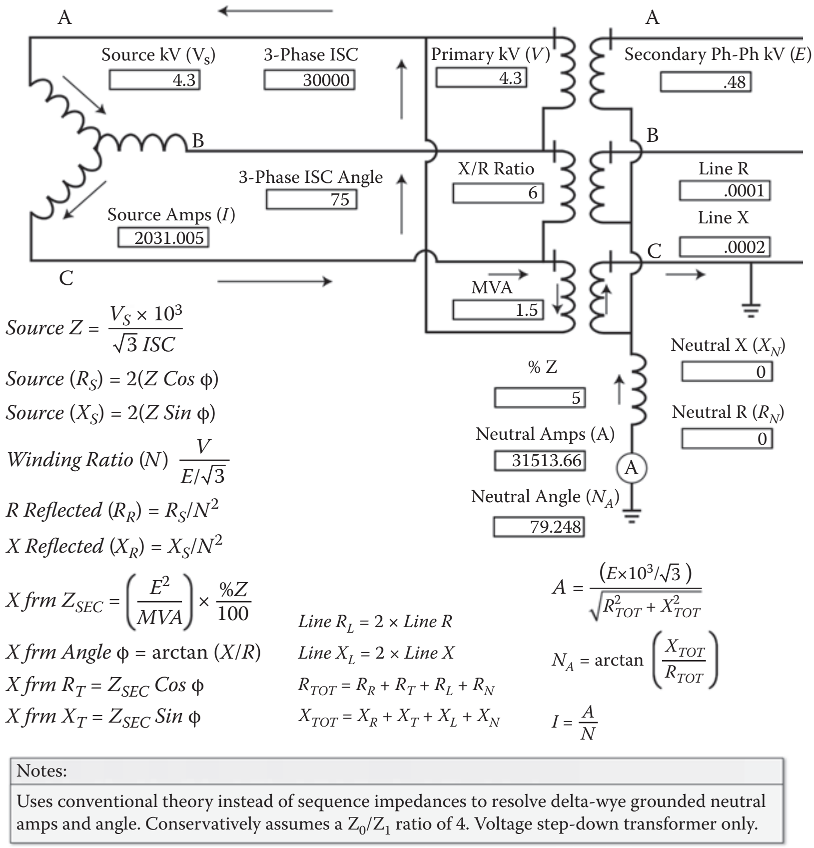


FIGURE 2.50
Alternative Ground Fault Calculation

calculated by dividing the base current by the direct axis saturated subtransient per-unit reactance or impedance. This is the reactance that is typically applied for short circuit studies and represents the flux magnitude prior to the fault. The *direct axis saturated subtransient reactance* (Xd″) is used when generators are at rated voltage (slightly saturated) prior to the fault and the pole faces are more directly aligned with load currents. A short circuit angle of 90 degrees lagging is often assumed for large generators, but if the X/R ratio is known, a more refined angle can be determined. The mid-level of fault current is calculated by dividing the base current by the direct axis saturated transient per-unit reactance (Xd′). This level of fault current typically lasts for tenths of seconds. The final level is determined by dividing the base current by the direct axis synchronous per-unit reactance (Xd). Please note that this level of current is normally well below the full load ampere rating of the machine; consequently, conventional overcurrent relays (without voltage restraint or control) cannot isolate generators from short circuits if they are

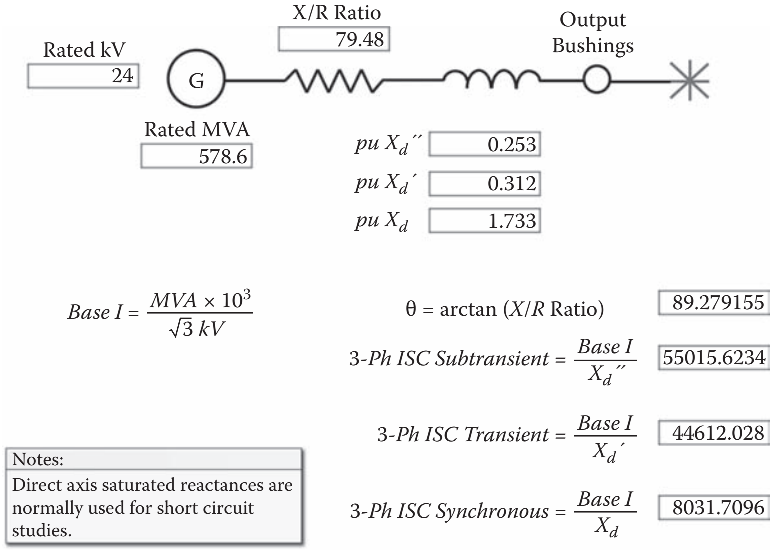


FIGURE 2.51
Generator Short Circuit

set with time delay to coordinate with downstream devices. The foregoing current decrements are basically caused by the inability of excitation systems to overcome the internal voltage drops and subtractive magnetic flux (armature reaction) that develop during large inductive reactive current flow in the stator windings. The synchronous reactance is also used to determine voltage drops in operating synchronous generators, and both the armature reaction and the inductive reactance are included in the Xd value. As with transformers, the initial phase-to-phase fault current for practical purposes is normally 86.6% of the three-phase subtransient value. Technically, double the negative phase sequence reactance should be used for the phase-phase calculation, but any differences are usually negligible.

2.10.7 Generator De-Excitation

The fault current decrement is determined by the excitation system and the trapped magnetic flux in the core iron and the subtransient, transient, and synchronous reactances for bolted or low impedance faults. If the fault impedances are higher, the decrement will take longer. This is a particular problem for short circuits on the secondary side of UATs on units that are not equipped with generator bus breakers. The UAT capacity (5% to 8%) is so small (high impedance) in relationship to the generator, that the generator continues to feed fault current after electrical isolation and the tripping of the prime mover.

Two pole generators generally decay faster than four pole machines. There are a couple of commonly used methods to reduce excitation current and

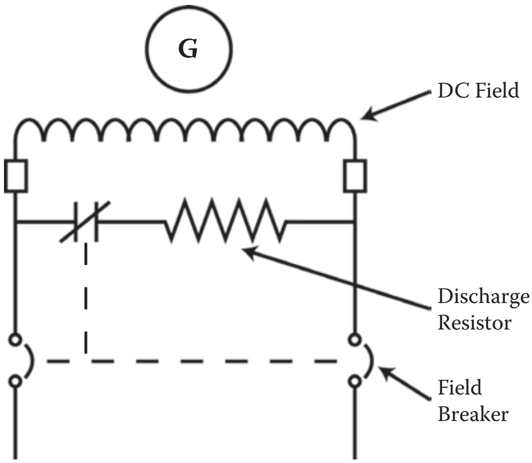


FIGURE 2.52
Direct DC Field Breaker

trapped magnetic flux in both machines. Figure 2.52 illustrates a direct field breaker; when the unit is tripped off-line, a resistor (often equal to the DC field ohms) is inserted across the field as the main contacts are in the process of opening to discharge the field current and trapped flux more rapidly. As generator designs grew larger in size during the 1970s, the DC excitation current became higher and direct field breakers became more expensive. Somewhere around 300 MVA and larger, it became more economical to indirectly interrupt the excitation power supply instead of the field current directly. Improved designs had de-excitation circuitry that reversed polarity on the field for faster fault current decrements. Although de-excitation circuitry was generally an option, it is often not used and difficult to apply on cross-compound units (HP and LP turbogenerators operated in parallel). Both the direct field breaker and the de-excitation circuitry reduce the UAT secondary fault current to approximately zero in around 4 seconds depending on design details. Because transformers are generally built to withstand the electromechanical forces from fault currents for only 2.0 seconds, it is not unusual to fail auxiliary transformers from through fault conditions that trip almost instantaneously from transformer differential protection. During the 1980s, a large coal plant in Nevada that was not equipped with direct field breakers or de-excitation circuitry developed a short circuit in the busway between the UAT and secondary circuit breaker. Although the UAT differential relays actuated and tripped the unit in around 6 cycles, the cross-compound generators continued to feed fault current to the short circuited secondary bus for 42 seconds during coast down. Obviously, the transformer required replacement after the event even though the fault was external and unit tripping was almost instantaneous.

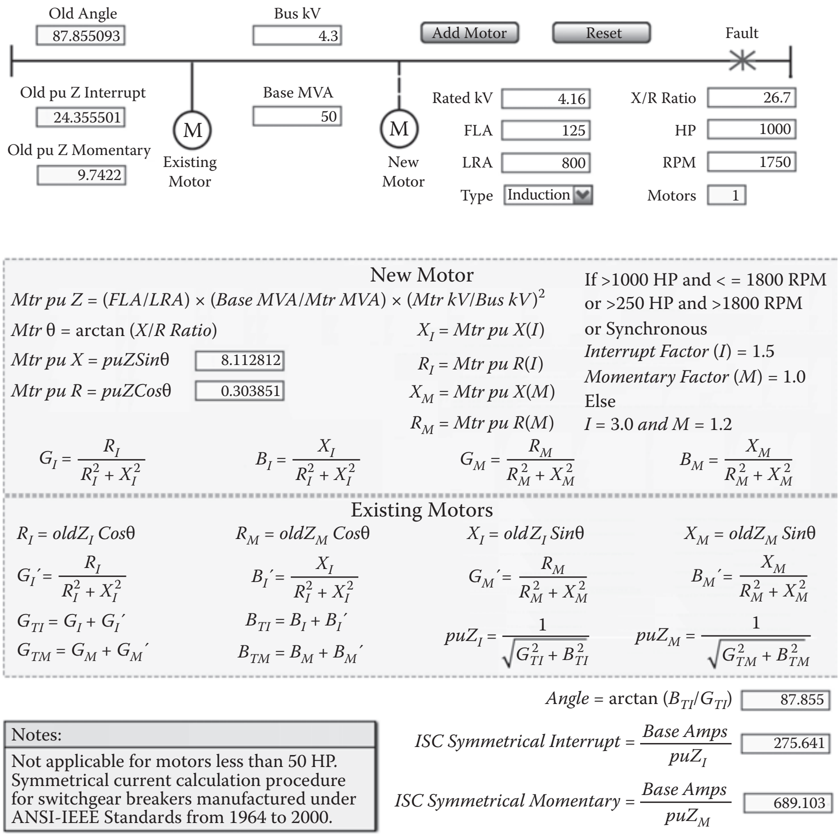


FIGURE 2.53
Motor Symmetrical Short Circuit Contributions

2.10.8 Motor Contribution

Motors can contribute current to short circuits for a few cycles because of the rotating inertia and trapped magnetic flux in the core iron. Normally, motor contribution does not need to be considered when coordinating overcurrent relays because of the rapid decay. However, it may need to be considered when analyzing instantaneous protection elements. It definitely needs to be included when calculating the interrupting and momentary short circuit current capabilities of switchgear circuit breakers. This will be discussed in more detail under circuit breaker duty calculations in Chapter 5. Figure 2.53 shows a procedure for calculating the symmetrical portion of motor current contribution for circuit breaker interrupting and momentary ratings and can also be used for other studies concerned with motor symmetrical current contribution. In the example, only one motor is considered in the calculation, and the old motor values represent that motor in advance of entering new data for the next motor. The motor per-unit Z is determined by dividing the motor full load amps by the maximum locked rotor amps. This value is then converted to a common MVA base, which should be equal to or greater in magnitude than the largest motor on the bus. Because the motor nameplate voltage is lower than the source bus voltage, the motor per-unit impedance also needs to be corrected to the bus voltage magnitude. Depending on the type of motor (synchronous or induction), horsepower, and RPM, different multiplication factors are applied to increase the motor per-unit impedances for interrupting and momentary symmetrical contributions, respectively, to account for current decrements during protective relay and circuit breaker operating times or cycles and specific motor design details.

The motor per-unit impedance is then added to other motors previously calculated using the conductance, susceptance, and admittance method of deriving parallel impedances. The total *symmetrical* interrupting and *momentary* current contributions for all motors on the bus can then be determined by dividing the base amps by the total interrupting and momentary per-unit impedances, respectively. Cable impedance is usually considered negligible for medium voltage motors but is normally considered for low voltage motors. For low voltage motors below 50 HP, usually the contribution is assumed to be 4 times full load amps, or 0.25 per unit.

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3

Auxiliary System Protection

In general, protection engineering requires a high degree of technical expertise and experience with the nuances and operation of generating stations. Practicing protection engineers also assume significant responsibility. They are concerned about personnel safety, and try to protect the apparatus on one hand and not cause nuisance tripping or unnecessary outages on the other. In essence, they are performing a balancing act and do their best to leave themselves in a defendable position. They also need to make sure that their settings coordinate with other relays or functions.

This chapter covers the protective relaying of low and medium voltage systems that provide the necessary auxiliary power for generating stations and industrial plants. Usually, protection engineers limit their scope to switchgear circuit breakers that are equipped with adjustable protective devices. This would normally include lighting transformer low side breakers; 480 volt buses that directly feed 75 to 299 horsepower (HP) motors, and motor control centers (MCCs), but not their positions; 4kV buses that feed 300 to 5000 HP motors and transformer loads; and 6.9 and 13.8 kilovolt (kV) buses that feed motors larger than 5000 HP.

3.1 Switchgear Overcurrent Coordination

Protective relay selectivity, or the tripping of the fewest components in order to isolate a short circuit condition, is achieved by having the lowest minimum trip value and the shortest time delay on the most downstream fault clearing device. As you move upstream toward the electrical source, each fault-clearing device should have progressively higher minimum trip (MT) values and longer fault clearing times to ensure coordination at all possible currents. Maximum symmetrical bus three-phase short circuit currents are normally used to compare tripping times for switchgear applications because the three-phase magnitude is normally the highest at the buses. In industrial plants, 0.3 seconds is generally considered the minimum amount of time between devices and may be a little marginal. Experience has shown that .25 seconds sometimes does not coordinate, and many in the industry prefer to use 0.4 seconds between upstream and downstream devices for a more conservative approach to ensure coordination. Curves with an inverse slope characteristic will have increased time margins at currents below maximum. The best practice is to apply the same curve type or slope (inverse, very inverse, or extremely inverse) for the bus tie, transformer low side breaker, and the high side or primary overcurrent protection. Where that is the case, little or no curve work will be necessary to ensure coordination. In relationship to low current levels, the more inverse the curves are, the faster the relays will actuate at higher currents. If the relays or devices coordinate properly, the outage impact to the station will be minimized and there will be a good indication as to the location of the fault allowing service to be restored quicker. The amount of time delay between positions is necessary to account for:

- Current transformer (CT) performance differences
- Relay calibration inaccuracies
- Electromechanical relay overtravel when the fault is interrupted
- Protective relay reset time (sequential events)
- Different relay curves
- Circuit breaker tripping time differences
- Circuit breaker interruption differences (which current zero?)
- Higher initial currents due to asymmetry and motor contribution
- Differences in transformer primary and secondary currents

Figure 3.1 illustrates a typical generating station auxiliary power system one-line configuration with the associated CTs and overcurrent relays. The most downstream overcurrent relays are for bus feeder breakers that drive motor, transformer, and MCC loads. Feeder breakers are equipped with instantaneous overcurrent elements (50) that will actuate in around 1 cycle for three-phase and phase-to-phase and ground (if solidly grounded) short circuits, and with breaker interruption time included isolate faulted feeders in around 6 cycles or 0.1 seconds. The fast operation clears faults before more upstream breakers can operate and have a greater impact on the auxiliary power system. Relay targets or flags will indicate which element and phase actuated to more quickly guide operations and maintenance to the problem area. The more upstream circuit breakers are not equipped with (50) instantaneous overcurrent elements and only have (51) time overcurrent functions because they need time delay to coordinate with bus feeder breakers. The shaded boxes in Figure 3.1 represent the amount of time delay for the maximum bus three-phase symmetrical short circuit current (usually around 30,000 amps) that is suggested for coordination purposes. As shown, the bus tie breaker has a time delay of 0.4 seconds to coordinate with feeder breakers. The low voltage side circuit breakers for the unit auxiliary, reserve auxiliary, and station service transformers (UAT, RAT, and SST, respectively) are upstream from the tie breakers and have time delays of 0.8 seconds for

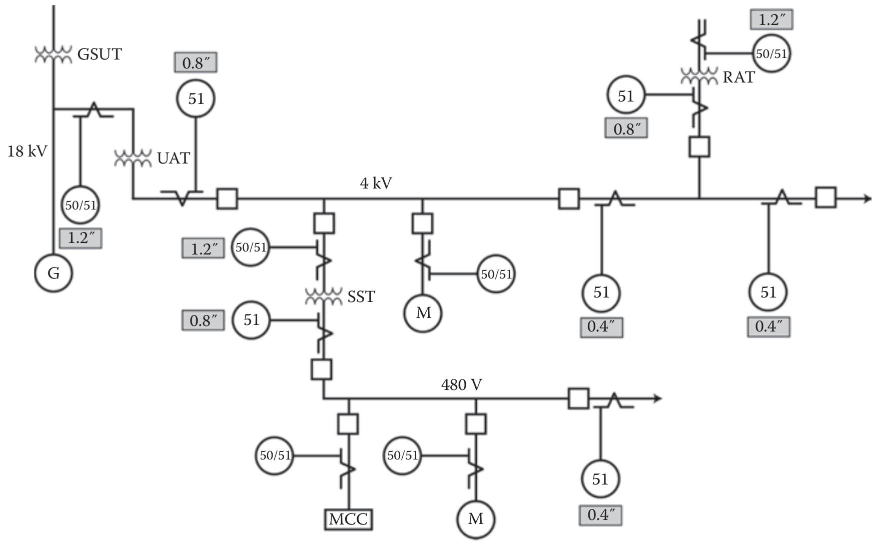


FIGURE 3.1
Typical Auxiliary System Overcurrent One-Line

three-phase bus faults, and the high side overcurrent elements have time delays of 1.2 seconds for secondary three-phase bus faults in order to coordinate with the low side relays. The transformer high side time overcurrent protection is absolutely necessary to provide breaker failure or stuck breaker protection in case the low side circuit breakers fail to clear bus short circuit conditions.

3.2 Overcurrent Schematic

Figure 3.2 presents a typical time overcurrent relay alternating current (AC) schematic for source, tie, and feeder breakers. As mentioned in the previous paragraph, the feeder breakers, in addition to the (51) functions, are also equipped with (50) instantaneous tripping elements. In the figure, one time overcurrent function (51) is provided for each phase. The phase relays are stared or tied together on the right side and the secondary currents are routed through a residual ground relay (51G) before returning to the neutral or stared side of the CTs. The ground relay can only actuate for ground faults and cannot see phase-phase and three-phase events and consequently can be set to operate below load current levels if the neutral does not carry load. Normally, only one safety ground is provided to facilitate testing of the secondary insulation. The dashed lines represent stray magnetic flux that always link with the secondary wiring, inducing small voltages. Induced current flows into the

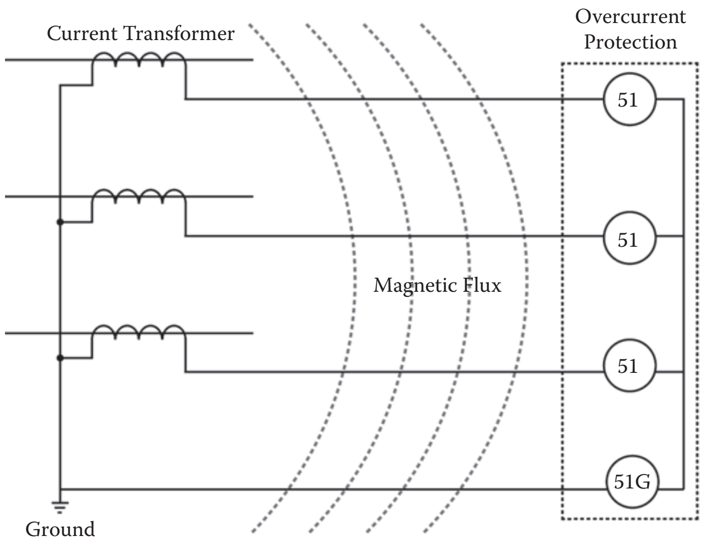


FIGURE 3.2
Typical Time Overcurrent Protection

relays are restricted by the CTs that block secondary AC current flow unless there is a corresponding current flow in the primary side. However, if the the CTs are shorted and primary current is flowing, the induced voltages and associated currents could actuate the 51G, which has greater sensitivity if the setting thresholds or minimum trip points are low enough.

3.3 Current Transformer (CT) Safety Ground

Figure 3.3 shows a donut CT wrapped around an energized 12 kV conductor. Stray capacitance is everywhere and there will be some level of internal capacitance between energized conductors and the secondary turns of the CTs and also stray capacitance between the external secondary wiring and ground. Consequently, there is a series voltage divider circuit between the energized conductor and ground. The phase-to-neutral voltage (6.9 kV) will have a path for current flow through the internal CT capacitance that is in series with the external wiring capacitance. If the stray capacitance between the 12 kV conductor and internal CT secondary wiring is higher (lower impedance) than the external wiring stray capacitance, the majority of the voltage will appear on the higher impedance secondary side. The safety ground shorts out the external wiring capacitance and prevents a voltage rise on the secondary side. Accordingly, energized CTs should be treated as

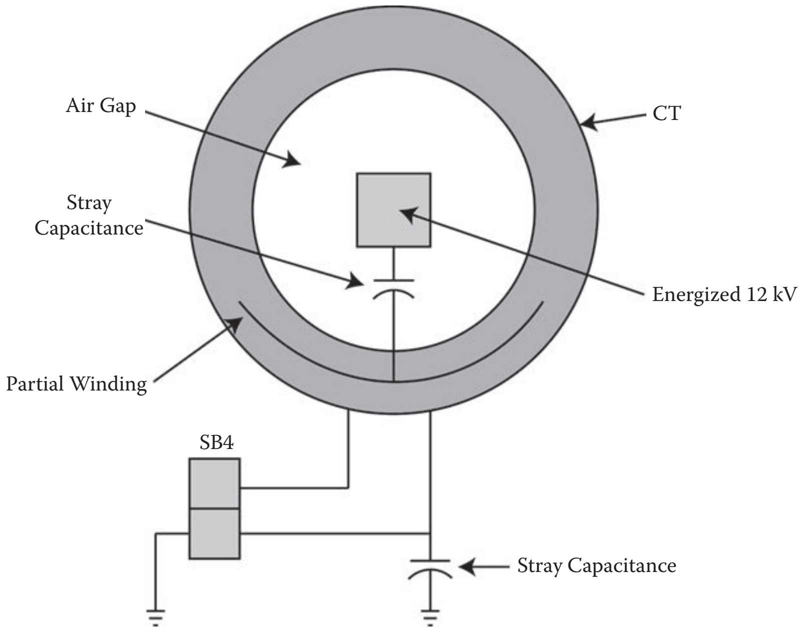


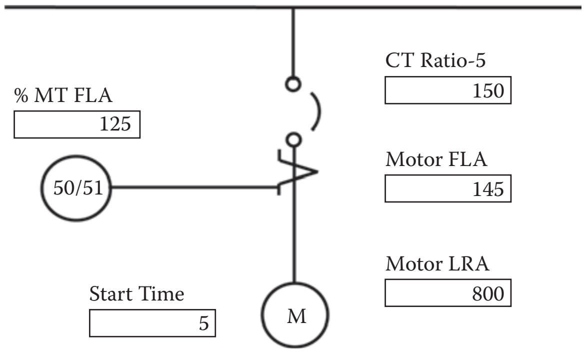
FIGURE 3.3
Current Transformer (CT) Safety Ground

hazardous even if the downstream circuit breaker is open and no current is flowing. It would be particularly risky or dangerous to lift the ground to perform a megohm test of the secondary insulation system.

3.4 Motor Overcurrent

For time overcurrent coordination purposes, it is usually easier to start with the most downstream devices and work your way upstream. For industrial plants, the most downstream devices would normally be bus feeder breakers or contactors that drive motors, MCCs, and other transformers.

Simple reliable induction-disk overcurrent relays, properly set, are very effective at providing motor protection over a wide range of operating conditions. As shown in Figure 3.4, the suggested minimum trip (MT) is 125% of nameplate full load amps (FLA). There is no specific time associated with the minimum trip threshold in an induction-disk relay. It is simply the amount of current where some movement of the disk is perceptible, and it could take all day to close the tripping contacts. Because motor cables are normally sized to continuously carry 125% of rated full load amps, the cables should be fully protected. Many motors are purchased with a 1.15 service factor or



$$Sec.\ MT\ Amps = \frac{\frac{\%\ MT}{100} \times FLA}{CT\ Ratio/5} \quad \boxed{6.042}$$

$$Sec.\ Timing\ Amps = \frac{LRA}{CT\ Ratio/5} \quad \boxed{26.667}$$

$$Time\ in\ Seconds = Start\ Time + 5.0 \quad \boxed{10}$$

$$Sec.\ IT\ Amps = \frac{2.5\ LRA}{CT\ Ratio/5} \quad \boxed{66.667}$$

Notes:
If the manufacturer's hot safe time curve is available, the timing seconds should be compared to the curve for acceptability. The start time must be accurate and represent actual operating conditions (motor loaded or unloaded during starting) to avoid nuisance trips.
These settings may not be appropriate for special applications where a practical thermal margin does not exist or the kVA of the motor approaches the kVA of the source transformer. In those cases, special relay schemes are required to properly protect the motors.

FIGURE 3.4
Motor Overcurrent Settings

have been rewound with higher temperature insulation systems that should provide an equivalent service factor of 1.15 or greater. Consequently, this setting does not provide thermal overload protection between 1.01 and 1.24 for some motors and 1.16 and 1.24 for most motors. Some designs do not have the capability to be overloaded beyond a 1.15 service factor. In other words, even if the dampers or valves are fully open, rated service factor full load amps may not be exceeded. The service factor is not a continuous rating and allows for temporary overload for an undefined time period. The weak link electrically during running is the stator windings, and approximately 37% of motor failure mechanisms are in that area. Accurate statistics on the specific causes of stator winding failures are not readily available. In addition to stator winding temperatures that can chemically degrade the insulation systems, there are many failure mechanisms involving shorted turns, switching

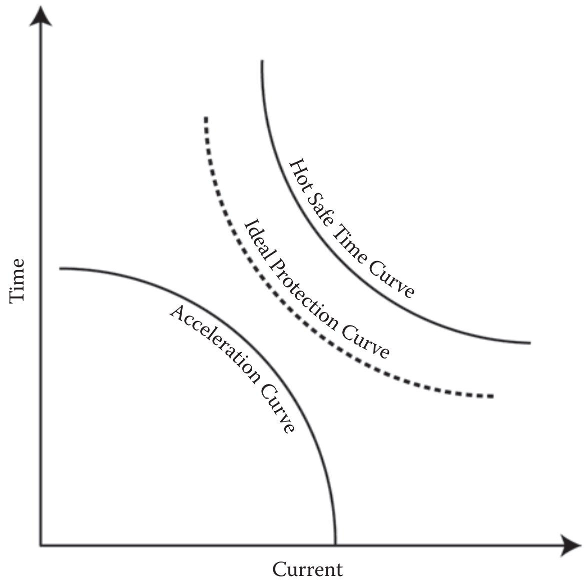


FIGURE 3.5
Motor Acceleration, Relay, and Hot Safe Time Curves

transients, ground transients, bus transfer forces, thermal expansion and contraction, electromechanical forces, partial discharges, end turn vibration, blocked cooling passages, hot spot locations, shorted laminations, and moisture and contamination intrusion. The manufacturer's thermal withstand margins are often based more on experience than on refined calculations.

The rotor is the weak link during starting. The timing is set for either 5.0 seconds longer than a normal start time at rated voltage maximum locked rotor amps (LRA) or under the motor hot safe time curves (motor initially at rated operating temperature) if the acceleration and thermal curves are available. Obviously, setting the relay curves halfway between the acceleration and hot safe time curves splits the margins for preventing nuisance tripping and protecting the apparatus, as shown in Figure 3.5. It is not unusual for motors greater than 5000 HP to not have sufficient thermal margins to fit the relay curve between the acceleration and safe time curves. For larger motors that lack sufficient margin, there are many schemes for providing adequate protection. The simplest involves using a zero speed switch and tripping the circuit breaker open if the motor fails to rotate in a specific amount of time. The thermal and acceleration curves were not automatically provided by manufacturers in the past unless specified in the motor purchase order; consequently, many existing plants do not have the curves. The suggested setting should prevent motor rotor damage for locked rotor conditions or for control malfunctions that do not properly unload the motor during starting. IEEE recommends 2 to 5 seconds beyond a normal start time depending on the relative acceleration durations. However, in the absence of specific thermal curves, because of nuisance tripping concerns, this writer is reluctant to use 2.0 seconds based on past experience with the variability of stop watch times, system voltages, relay curves, and control system unloading. Care must be taken that the normal start time represents actual operating conditions to prevent nuisance tripping, that is, motor loaded or unloaded during starting. Additionally, the design margins for rotors may be dictated by experience and not necessarily refined calculations.

Short circuit coordination with the bus source breaker protection is achieved with the instantaneous overcurrent setting. A setting of 250% of rated voltage maximum locked rotor amps is shown in Figure 3.4. The 250% figure is the maximum IEEE recommendation for providing margin above asymmetrical LRA values that are generally assumed to be 160% higher (depending on X/R ratios) to prevent nuisance tripping during starting conditions. The worst case for asymmetrical currents is when the sine wave is at zero crossing at the time the breaker contacts close. This reduces the rate of change and the corresponding self flux and impedance, which momentarily causes a higher than normal phase current to flow. There may also be additional effects from residual magnetism in the iron laminations. Because of the high setting, the instantaneous element can be actuated only by high magnitude short circuit currents and not by asymmetrical starting currents or unusual operating conditions. Except in somewhat rare cases, there is no reason to set the instantaneous trip point lower, because more than adequate margins between the 250% setting and available fault current levels are normally provided. If the instantaneous element fails to actuate, the (51) time overcurrent function should operate in a relatively short period of time.

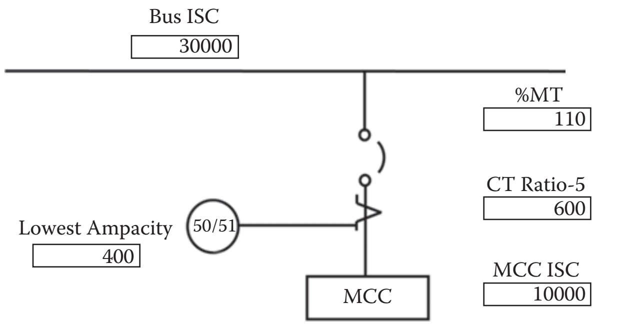
The newer digital relays have some advantages over the older induction-disk relays. By NEMA (National Electric Manufacturers Association) standard, motors are designed for two starts in succession with the rotor coasting to rest between starts when initially at ambient temperature. The coasting to rest requirement is provided to give higher inertia motors more time to cool down because the stored heat in the rotor from a longer acceleration period will be greater. If the motor is at rated operating temperature, only one start is permitted. Many plants have an operating procedure that requires a one-hour cooling period before permitting a third start; the motor can be at rest or running during the cooling period. The newer digital relays provide various degrees of thermal modeling of the rotors, stators, or both. This thermal modeling may prevent motor abuse from too many starts in succession or insufficient cooling periods and also may protect larger motors that lack sufficient thermal margins for overcurrent protection. However, in the case of induction-disk relays, the number of starts or cooling period could easily be programmed into the plant digital control system (DCS). The thermal modeling is complex, has long time constants that are difficult to test, and may not accurately represent the motor. Improved thermal modeling can be achieved by bringing stator resistance temperature device (RTD) inputs into some relay models, but they may not accurately reflect hot spot temperatures and may not be able to respond fast enough to protect the motor from severe rotor events, that is, stalled or locked rotor conditions.

3.5 Motor Control Center (MCC) Source Overcurrent

MCC source feeders can be a little tricky to set without increasing the time delay on upstream source breakers for the bus. If the MCC is located adjacent to the switchgear, the instantaneous element will need to be disabled or set well above maximum asymmetrical short circuit current magnitudes at the MCC. However, in low voltage systems (480 volts), the fault current drops off fairly fast as the distance and cable impedance from the switchgear to the MCC increase. Assuming three-phase short circuit magnitudes of 30,000 amps for both 4 kV and 480 volt buses and a 4/0 cable run of 200 feet each, the 4 kV current would be 27,918 (89%) and the 480 volt three-phase short circuit would be 13,010 amps (43%) at the end of the cable. If the switchgear bus three-phase amps short circuit (ISC) is at least twice the magnitude of the short circuit current at the MCC, the instantaneous element can be applied. A fault current ratio of 2.0 or greater (main bus ISC/MCC bus ISC) will prevent a 200% instantaneous element from operating for asymmetrical faults (160%) at the MCC and will allow for coordination with downstream MCC positions. If the ratio is less than 2.0, the instantaneous element may need to be disabled to mitigate the possibility of nuisance tripping and time delay may need to be added to the switchgear bus source breaker relays to ensure coordination. Figure 3.6 covers the MCC source feeder overcurrent settings. The suggested minimum trip is 110% of the lowest ampere rating in the MCC feeder circuit. This could be the source feeder breaker, cables, or MCC bus. The suggested time delay of 0.4 seconds at the MCC maximum three-phase symmetrical short circuit current should coordinate with downstream MCC positions, as they are normally equipped with some form of instantaneous overcurrent protection. If the instantaneous elements cannot be applied, the MCC source feeder breaker relay curves should be compared with the switchgear bus source breakers at 25%, 50%, 75%, and 100% of the three-phase main bus fault current to ensure coordination at possible current levels.

3.6 Bus Tie Overcurrent

The next upstream device depending on the bus configuration would normally be the bus tie breaker. This breaker is used to feed the bus from a second



$$\text{Sec. MT Amps} = \frac{\frac{\%\,MT}{100} \times \text{Lowest Ampacity}}{CT\ Ratio/5} \quad \boxed{3.666667}$$

$$\text{Sec. Timing Amps} = \frac{MCC\ ISC}{CT\ Ratio/5} \quad \boxed{83.333333}$$

$$\text{Time in Seconds} \quad \boxed{0.4}$$

$$\text{Sec. IT Amps} = \frac{2 \times MCC\ ISC}{CT\ Ratio/5} \quad \boxed{166.666667}$$

Notes:
The lowest ampacity is normally the ampere rating of the cables that feed the MCC or the MCC bus rating. If the ratio of bus ISC/MCC ISC is less than 2.0, a more detailed coordination study should be completed. If the ratio is less than 3.0, the MCC curves should be compared with the bus tie curves for proper coordination at 25%, 50%, 75%, and 100% of the MCC IT amps.

FIGURE 3.6
Motor Control Center (MCC) Source Feeder Overcurrent

source if the normal source is not available (unit trip or in startup) or is out for maintenance. Only feeder breakers or the most downstream device should be equipped with instantaneous overcurrent elements. Source and tie breakers need to coordinate with downstream devices; consequently, instantaneous overcurrent elements cannot be used for those positions. Bus tie overcurrent relays can be a little tricky to set because the bus tie breaker needs to handle the starting current for all connected motors on the bus during automatic bus transfer operations and also bus parallel currents when the voltage or power angles between the two buses are different. Depending on the transformer impedances, 10-degree voltage phase angle differences between the UAT and RAT can cause more than rated current to flow across the tie breaker.

Many motors stay approximately at locked rotor current levels until reaching around 90% speed. Accordingly, motors that are de-energized can be in starting current very quickly when re-energized during bus transfers. Figure 3.7 illustrates a procedure for roughly estimating combined starting current magnitudes from motor loads during bus transfer conditions. For illustration purposes, four identical motors are shown in the procedure. The combined locked rotor current is roughly estimated at 85% because

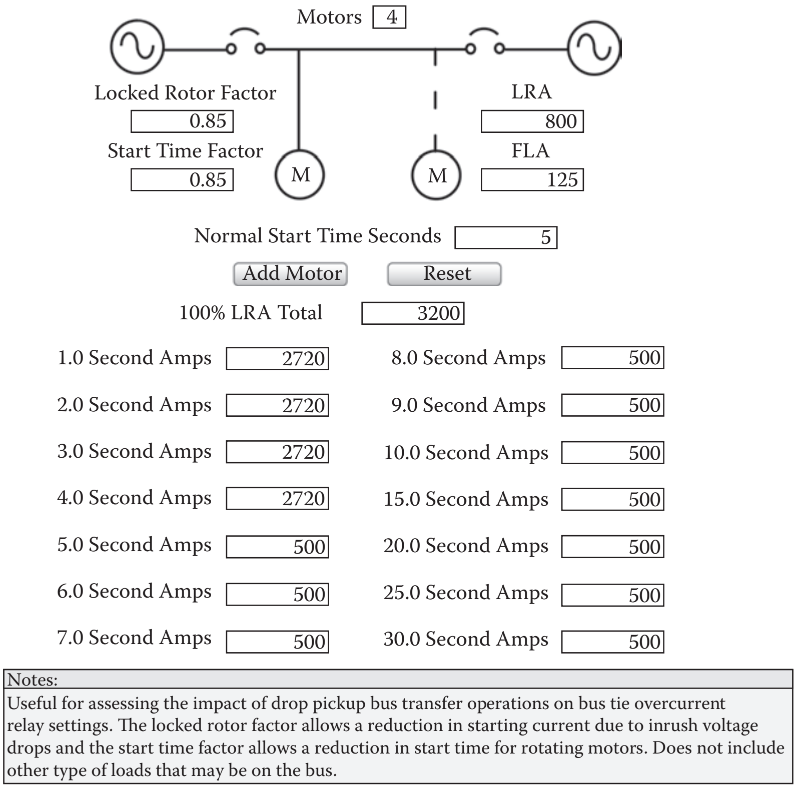


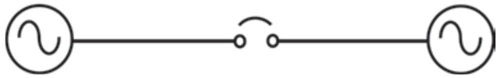
FIGURE 3.7
Motor Loads during Transfer

the bus voltage will be somewhat depressed from the high motor starting load. The start time is also roughly estimated at 85% because the motors are still rotating and not stopped when the transfer occurs. As illustrated in Figure 3.7, the combined current stays relatively high at 2720 amps for 4.0 seconds before it reduces to a full load ampere level. The higher current level and time can then be compared to the relay curves to see if there is a possibility of nuisance tripping. Obviously, having a digital record of actual currents during bus transfer conditions would be preferred over estimating the current inrush levels.

Figure 3.8 calculates the amount of current that will flow when two systems are operated in parallel with a delta voltage angle of 10 degrees. A similar calculation is presented in Chapter 2 with some minor differences. For convenience, the circuit X_L has been replaced with short circuit values for each bus and the X_L determined for each bus with a three-phase version of Ohm's Law. The procedure also uses standard power formulas to determine megavolt-amps (MVA) and the magnitude of current flows between the two systems.

Bus 1 3-Ph ISC: 30000

Bus 2 3-Ph ISC: 30000



Bus 1 Ph-Ph kV: 4.4

Bus 2 Ph-Ph kV: 4.3

Degrees Out of Phase (δ): 10

$$V_1 = kV_1 \times 10^3 \qquad V_2 = kV_2 \times 10^3$$

$$Z_1 = \frac{V_1}{\sqrt{3}\, ISC_1} \qquad Z_2 = \frac{V_2}{\sqrt{3}\, ISC_2}$$

$$MW = \left(\frac{V_1 \times V_2}{Z_1 + Z_2}\right) Sin\, \delta \times 10^{-6}$$ 19.622

$$MVAR = \left(\frac{V_2}{Z_1 + Z_2}\right)(V_1 Cos\, \delta - V_2) \times 10^{-6}$$ 0.851468

$$MVA = \sqrt{MW^2 + MVAR^2}$$ 19.64

$$Amps = \frac{MVA \times 10^6}{\sqrt{3}\, V_1}$$ 2577.206

Notes:
Useful for assessing the impact of out-of-phase parallel operations on bus tie overcurrent relays.

FIGURE 3.8
Bus Parallel Currents

Figure 3.9 covers a procedure for calculating settings on bus tie overcurrent relays. Medium voltage 4 kV feeder breakers are usually rated for 1200 amps continuous and source and tie breakers at 2000 or 3000 amps. In this example, the bus tie breaker is rated for 2000 amps, and the suggested value for the secondary minimum trip point is 110% of the lowest ampacity, or 2200 amps. The lowest ampacity could be the transformer, switchgear bus, circuit breaker, or cables/busway between the transformer and low side breaker or beyond the bus tie breaker. The timing is set for 0.4 seconds at the maximum three-phase symmetrical short circuit current. This setting assumes that the timing does not need to be increased to accommodate a feeder load that does not utilize instantaneous overcurrent elements.

The 2200 amp minimum trip value is below the bus transfer currents of 2720 amps in Figure 3.7 and is also below the bus parallel currents of 2577 amps in Figure 3.8. The motor bus transfer currents can be compared to the relay curves to see if it will be a problem. In this case, the out-of-phase parallel currents will be a problem unless automatic circuitry or operator

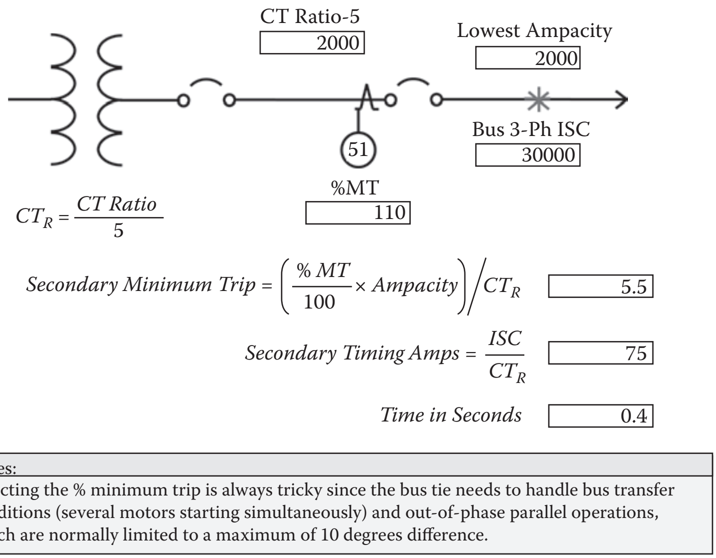
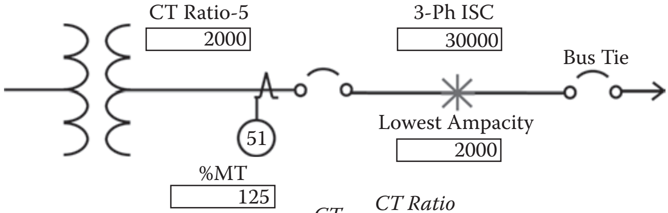


FIGURE 3.9
Bus Tie Overcurrent Settings

action limits the duration of the parallel. In general, parallel operation should be limited to a few seconds, and bus parallels with delta angles greater than 10 degrees should not be permitted. A safe angle range can be calculated using the procedure presented in Figure 3.8 and supervised administratively with operator synchroscope angle estimates or by sync check relays. If the delta angles are too great, the unit output megawatts (MW) would need to be reduced to bring the angles into a more favorable range. The delta angles may be greater for designs that generate into bulk power (230 kV) but utilize sub-transmission (69 kV) to feed the RAT. During temporary parallel operation of the unit with the reserve 4 kV buses, the combined short circuit currents will usually exceed the current interruption capability of feeder breakers. Most plants assume a risk that a severe fault will not occur during the short duration of parallel. If it did occur, the source and tie relays would time out to clear the fault, but the feeder breaker could be severely damaged from downstream faults.

3.7 Transformer Secondary Side Overcurrent

Setting transformer secondary side overcurrent relays is relatively easy. As Figure 3.10 illustrates, the suggested minimum trip value is 125% of the



$$CT_R = \frac{CT\ Ratio}{5}$$

$$Secondary\ Minimum\ trip = \left(\frac{\%\ MT}{100} \times Ampacity\right) \Big/ CT_R \quad \boxed{6.25}$$

$$Secondary\ Timing\ Amps = \frac{ISC}{CT_R} \quad \boxed{75}$$

$$Time\ in\ Seconds \quad \boxed{0.8}$$

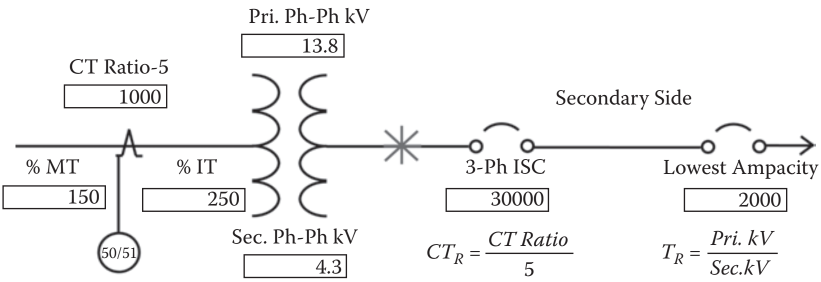
Notes:
If the timing characteristic curves for the bus tie overcurrent relays are different, check for proper coordination at 10%, 25%, 50%, and 75% of timing current. Typical practice is to provide at least 0.4 seconds time between upstream and downstream relays.

FIGURE 3.10
Transformer Secondary Side Overcurrent Settings

lowest ampacity or 15% higher than the bus tie breaker. The timing is set for 0.8 seconds or 0.4 seconds longer than the bus tie overcurrent relays at the same maximum three-phase symmetrical short circuit current. If the relay curves have the same slope characteristics as the bus tie relays, comparing the curves to ensure coordination at all points will not be necessary.

3.8 Transformer Primary Side Overcurrent

In addition to protecting the transformer, the primary side overcurrent relays provide backup protection for transformer differential relays, if equipped, and stuck breaker protection for the secondary side breaker if it fails to properly clear a short circuit condition; because the fault could be in the transformer or upstream of the secondary circuit breaker, fault isolation requires complete transformer de-energization. Setting transformer primary side overcurrent relays is also relatively easy. Figure 3.11 is applicable for RATs, UATs, and SSTs. The suggested minimum trip value is 150% of the lowest ampacity or 25% higher than the secondary overcurrent relay minimum trip thresholds. Figure 3.12 presents a calculation to determine the overload capability of transformers built to IEEE standards. The calculation does not provide accurate results if the overload currents are close to full load amps and assumes an I^2T number of 1250 with the lower transformer MVA or "OA"



$$CT_R = \frac{CT\ Ratio}{5} \qquad T_R = \frac{Pri.\ kV}{Sec. kV}$$

$$Secondary\ MT\ Amps = \frac{(Lowest\ Ampacity/T_R)}{CT_R} \times \frac{\%\ MT}{100} \qquad \boxed{4.673913}$$

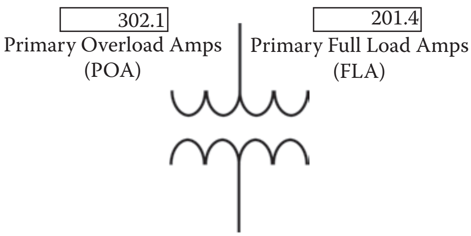
$$Secondary\ Timing\ Amps = \frac{(ISC/T_R)}{CT_R} \qquad \boxed{46.739130}$$

$$Time\ in\ Seconds \qquad \boxed{1.2}$$

$$Secondary\ IT\ Amps = \frac{(ISC\ (\%IT/100)/T_R)}{CT_R} \qquad \boxed{116.847826}$$

Notes:
If the timing characteristic curves for the secondary side overcurrent relays are different, check for proper coordination at 10%, 25%, 50%, and 75% of the timing current. If the transformer is wye-delta or delta-wye connected, a phase-phase fault on the secondary side will produce three-phase fault magnitudes on the primary side. Accordingly, check for proper relay coordination with 86.6% three-phase ISC on the sccondary side and 100% three-phase ISC on the primary side.

FIGURE 3.11
Transformer Primary Side Overcurrent Settings



$$Withstand\ Seconds = \frac{1250}{(POA/FLA)^2} \qquad \boxed{555.556}$$

$$Withstand\ Minutes = \qquad \boxed{9.259}$$

Notes:
Use the lower or "OA" rating to determine FLA. Per IEEE standards, transformers have an I^2T rating of 1250 at higher currents. This calculation is not applicable for currents that are close to full load amps.

FIGURE 3.12
Transformer Overcurrent Withstand

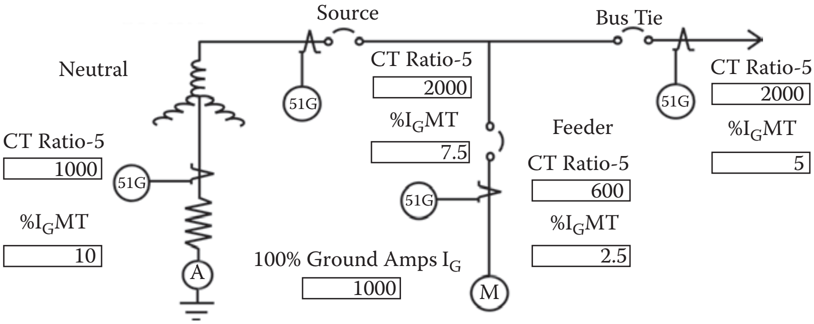
rating used to determine 1.0 per-unit full load amps. The results indicate that a power transformer can withstand 150% load for $1250/1.5^2$ or 556 seconds or 9.26 minutes.

The timing is set for 1.2 seconds or 0.4 seconds longer than the secondary side overcurrent relays at the maximum three-phase symmetrical secondary short circuit current divided by the transformer turns ratio. Generally, due to electromechanical magnetic force limitations, transformers are built to withstand external short circuit conditions for 2.0 seconds. Accordingly, the primary overcurrent relays should trip the transformer off-line in less than 2.0 seconds at maximum secondary side fault current levels. If the relay curves have the same slope characteristics as the secondary side overcurrent relays, comparing the curves to ensure coordination at all points will not be necessary. However, if the transformer configuration is delta-wye or wye-delta, a phase-to-phase fault on the secondary side will cause increased currents to flow in one phase on the primary side, as explained in the preceding chapter. If this is the case, there must be adequate timing margin between the primary and secondary relays curves, with 86.6% of the maximum three-phase fault current on the secondary side and 100% of the maximum three-phase secondary fault current on the primary side.

Instantaneous elements can be applied for transformer high side protection. As shown in Figure 3.11, the suggested setting is 250% of the maximum three-phase symmetrical short circuit current for a secondary side fault. Although not absolutely guaranteed, experience has shown that a 250% setting will not cause nuisance tripping during transformer magnetizing inrush conditions and is well above possible secondary asymmetrical short circuit current magnitudes. The instantaneous element will not see short circuit events on the secondary side, which is desirable for coordination reasons.

3.9 Residual Ground Protection

Many modern generating stations and large industrial facilities connect resistors from auxiliary system transformer wye neutral bushings to ground to limit the magnitude of available ground fault current. This has a number of advantages including a reduction in personnel hazards and the mitigation of motor iron damage. Other advantages will be addressed later, under the section titled "High Impedance Grounding." The amount of ground fault current reduction is limited by the transformer secondary bus breaker CT ratios and the sensitivity or range of the protective relays applied for that purpose. A typical limited ground fault current value for large generating station auxiliary systems is around 1000 amps. Because the 100% ground fault current is in the load range, the magnitude can be determined by simply dividing the phase-to-neutral voltage by the neutral resistance. The



$$\textit{Feeder Sec. MT} = \left(I_G / \frac{CT\ Ratio}{5}\right) \times \left(\frac{\%MT}{100}\right) \qquad \boxed{0.208333}$$

$$\textit{Feeder Sec. Timing Amps} = I_G / \left(\frac{CT\ Ratio}{5}\right) \qquad \boxed{8.333333}$$

$$\textit{Feeder Seconds} \qquad \boxed{0.3}$$

$$\textit{Bus Tie Sec. MT} = \left(I_G / \frac{CT\ Ratio}{5}\right) \times \left(\frac{\%MT}{100}\right) \qquad \boxed{0.125}$$

$$\textit{Bus Tie Sec. Timing Amps} = I_G / \frac{CT\ Ratio}{5} \qquad \boxed{2.5}$$

$$\textit{Bus Tie Seconds} \qquad \boxed{0.7}$$

$$\textit{Source Sec. MT} = \left(I_G / \frac{CT\ Ratio}{5}\right) \times \left(\frac{\%MT}{100}\right) \qquad \boxed{0.1875}$$

$$\textit{Source Sec. Timing Amps} = I_G / \frac{CT\ Ratio}{5} \qquad \boxed{2.5}$$

$$\textit{Source Seconds} \qquad \boxed{1.1}$$

$$\textit{Neutral Sec. MT} = \left(I_G / \frac{CT\ Ratio}{5}\right) \times \left(\frac{\%MT}{100}\right) \qquad \boxed{0.5}$$

$$\textit{Neutral Sec. Timing Amps} = I_G / \frac{CT\ Ratio}{5} \qquad \boxed{5}$$

$$\textit{Neutral Seconds} \qquad \boxed{1.5}$$

Notes:
Feeder IT elements are normally disabled to mitigate the possibility of erroneous tripping due to CT saturation. If relay curves are different, check for coordination at 10%, 25%, 50%, and 75% of I_G.

FIGURE 3.13
Residual Ground Overcurrent Settings

residual ground relays are connected between the CT neutral point and the star point for the phase relays. Only ground current and not phase-to-phase or three-phase current will be detected by these relays.

Figure 3.13 illustrates a complete residual ground scheme with the exception that only one feeder breaker is shown. Relay settings for feeders with different CT ratios will need to be calculated separately. Instantaneous elements should not be applied because of concern over inadvertent tripping from CT saturation from asymmetrical currents during feeder motor starting and transformer magnetizing inrush conditions. Error currents from saturated CTs will likely impact only one phase and, consequently, will look like ground fault current to the residual ground relay. A time delay of 0.3 seconds on downstream feeder breaker ground protection is suggested to allow asymmetrical currents to decay to more reasonable levels. Because the relays do not see load current, the minimum trip values can be set low. In this case, 2.5% of the maximum ground fault current has been selected for the feeder breaker minimum trip with a time delay of 0.3 seconds at the 100% ground fault current. The next upstream device, the bus tie position, has a suggested minimum trip of 5% with a timing of 0.7 seconds at the maximum ground current. The source breaker has a suggested minimum trip value of 7.5% and a time delay of 1.1 seconds at maximum ground current. The final or most upstream ground relay is connected to a CT on the source transformer neutral and has a suggested minimum trip of 10% and a time delay of 1.5 seconds at maximum ground current and requires complete de-energization of the transformer. The neutral relay is necessary to detect ground faults upstream of the transformer secondary side breaker. Again, the suggested settings are dependent on the range or sensitivity of the associated relays, and an iterative approach may be required before the final settings can be determined.

3.10 High Impedance Grounding

High impedance ground schemes are typically applied in generating stations, refineries, combustibles areas, and industrial facilities where phase-to-neutral voltages are not utilized to feed loads. Three types of ground detection schemes are normally employed: residual ground (already discussed), neutral grounding transformers, and grounded wye–broken delta grounding transformers. Residual ground schemes are commonly used for medium voltage applications (4 kV), neutral high impedance grounding is used for almost all medium to large size generators to detect stator ground faults and also on older medium voltage auxiliary systems, and grounded wye–broken delta grounding is used primarily on low voltage 480 volt delta systems, and to detect grounds between generator breakers and their associated step-up transformers.

This writer is an advocate of high impedance grounding because of the significant number of advantages it provides over solidly grounded systems, especially in the area of personnel safety. High impedance grounding provides the following benefits over solidly grounded systems:

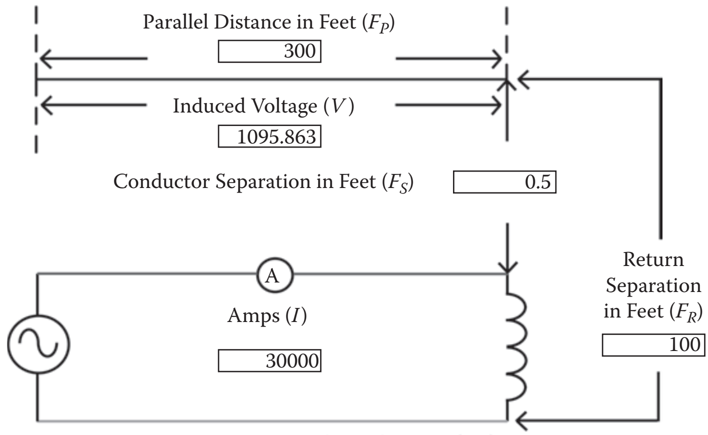
- Significantly reduces personnel electrical hazards
- Mitigates the likelihood of fires and explosions

- Reduces exposure to induced voltages
- Reduces exposure to step and touch potentials
- Prevents the flow of high magnitude ground fault currents from the accidental or inadvertent dropping of tools or material on energized phase conductors
- Reduces unplanned electrical shutdowns
- Mitigates motor iron damage
- Reduces short circuit duty near the source
- Is inexpensive to install or retrofit

As previously mentioned, unlimited ground fault currents are higher than three-phase short circuit amperes near the source transformer. Limiting the ground fault magnitude can lower the short circuit duty at the secondary source breaker, prevent motor iron damage, and reduce the likelihood of fires and explosions. Accordingly, hazards to plant operators, electricians, and technicians who work around energized medium (4 kV) and low voltage (480 volt) systems are significantly reduced with high impedance grounding. With the exception of generator protection, these schemes alarm only and, consequently, do not result in the immediate shutdown of plant equipment or the facility. However, the voltage developed on the unfaulted phases to ground increase by a factor of 1.732 for a 100% ground, which normally exceeds the continuous voltage rating of the cables and insulations systems associated with the particular auxiliary power system. Cable insulation ratings are often phase-to-phase and may not denote the phase-to-ground capability; that is, a 600 volt three-conductor cable may only be continuously rated for 600/1.732 or 346 volts to ground, and 5 kV cable is usually rated for 2.9 kV to ground. Accordingly, facilities applying alarm-only high impedance grounding schemes should have procedures in place to quickly isolate grounded feeders or buses before they develop into damaging high current double line to ground, phase-to-phase, and three-phase short circuits from the increase in voltage on the unfaulted phases. Experience has shown that the temporary increase in phase-to-ground voltage is not a problem for healthy cables and motors. However, there are reports of surge capacitor failures from increases in phase-to-ground voltages. The surge capacitors represent a capacitive load and the increase in voltage on the unfaulted phases thermally overloads the capacitors from the higher current flow.

3.10.1 Induced Voltages

Another advantage of high impedance grounding is the limiting of hazardous induced voltages into structures and raceway conductors by unlimited ground faults. Figure 3.14 presents an induced voltage calculation that discloses that an unlimited ground or double line to ground fault in a cable that



$$V = .2794\, I \left(\frac{F_P}{5280}\right) Log_{10}\left(\frac{F_R}{F_S}\right)$$

Notes:
Calculates the voltage induced into an adjacent conductor by 60 Hz unbalanced current flow in an industrial facility. The imbalance can be caused by phase to ground of double line to ground faults or by circuit designs that allow the return current to take a different path. See *Westinghouse Transmission and Distribution Reference Book* under low frequency coupling for further information.

FIGURE 3.14
Induced Voltages

parallels an adjacent de-energized circuit in a duct bank or cable tray for as little as 300 feet can induce over 1 kV into the de-energized circuit from the magnetic flux linkage. As the calculation shows, the amount of induced voltage is impacted by the current magnitude, the separation distance between the circuits and the location of the ground current return path. Increasing the current, parallel distance, and return path separation and reducing the distance between circuits will increase the magnitude of the induced voltage.

Figure 3.15 illustrates an electrician disconnecting a motor on a de-energized circuit. Prior to the Occupational Safety and Health Act (OSHA) of 1970, it was standard practice to rack out switchgear circuit breakers as part of an electrical clearance or tag-out procedure and then disconnect or break motor splices or terminations for maintenance reasons with bare hands. Following OSHA, many plants began purchasing switchgear grounding breakers that could be racked into cubicles to effectively ground the motor and feeder cables at the switchgear end. This procedure, which is still commonplace in the industry, has a number of disadvantages: first, breakers are individually adjusted or custom fitted to mate with their rake-in mechanisms and primary disconnects and racking in general purpose (non–custom fitted) grounding breakers may damage or wear out electrical current carrying disconnects and racking mechanisms. Second, the grounding breaker

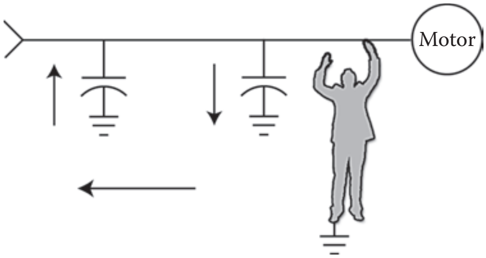


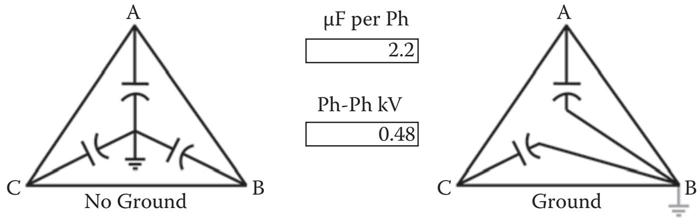
FIGURE 3.15
Induced Voltage Hazard

makes it more dangerous for the worker because of its remote location. Safety grounds are applied to protect workers from induced voltages and inadvertent energizations. In the case of induced voltages, the grounds need to be adjacent or close to the worker, and grounds at the remote switchgear end increase the induced voltage hazard. For modeling purposes, one-half of the distributed cable capacitance is shown at each end of the motor cables in Figure 3.15. A 1 kV induced voltage in the motor cables (Figure 3.14) will push current through both the worker and distributed capacitance at the motor location and then through the distributed capacitance at the switchgear end to complete the circuit. Grounding the switchgear end bypasses the current limiting capacitive reactance at that location, causing additional current to flow through the worker. Obviously, in the case of an inadvertent energization, the grounding breaker cannot be in place if it occurs. The safer alternative would be to rack out the breaker, treat the circuit as energized, and then disconnect the motor while wearing protective gloves. Personal grounds can then be applied at the motor end of the cables once they are disconnected from the motor.

Although high impedance grounding eliminates harmful induced voltages from ground faults, it does nothing to eliminate the possibility of higher induced voltage magnitudes from double line to ground faults. If the ground is not isolated before it develops into a double line to ground fault, the induced voltages could be much more serious or hazardous. For example, A phase could fail to ground initially, and then C phase on a different feeder on the other side of the facility. This would significantly increase the return path separation and the calculated induced voltage magnitude.

3.10.2 Transient Voltage Mitigation

Figure 3.16 illustrates the before and after conditions of grounding a floating (nongrounded) three-phase power source. When a ground occurs, the voltage on the unfaulted phases to ground increases by the square root of 3, or 1.732 (phase-to-phase). If the ground is spitting or intermittently arcing, the insulation system capacitance can cause voltage doubling as the configuration



$C = \mu F/10^6$

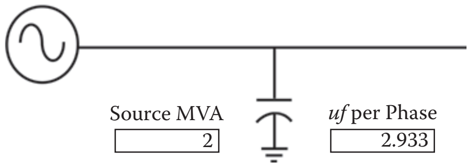
$$I_{chg} = \frac{Ph\text{-}Ph\ kV \times 10^3}{\left(\dfrac{1}{2\pi \times 60 \times C}\right)} \times \sqrt{3} \qquad \boxed{0.68953}$$

Notes:
I_{chg} is the total amount of capacitive current that will flow if one phase of a floating three-phase system is grounded.

FIGURE 3.16
Capacitive Charging Amps

repeatedly and rapidly goes from the ungrounded to the grounded mode. It is generally thought that in industrial facilities, the transient voltages developed during arcing ground conditions can get as high as 6.0 per unit and are typically in the 1 to 20 kilohertz range. This level of transient voltage can fail the insulation on unfaulted phases causing high damaging double line to ground short circuit currents to flow.

When one phase of a floating system is grounded, it unbalances the insulation capacitance and a capacitive or charging current flow can be measured to ground. As can be seen in Figure 3.16, the ground shorts out the capacitance for one phase and the remaining two will allow current to flow. The current for each can be determined by dividing the phase-to-phase voltage by the associated X_C and then multiplying by the square root of 3, or 1.732, to determine the total capacitive current flow, since they are 60 degrees apart. The general rule of thumb is to have the ground detector scheme provide a resistive current that equals the capacitive or charging amps that flow when one phase is 100% grounded. This will reduce the maximum voltage transient from 6.0 to around 2.4 per unit and is equivalent to installing resistors in parallel with the insulation capacitance to keep charge levels and resulting voltage increasing levels lower. Although any amount of resistive current provided by the ground detector will reduce the transient voltage from maximum, resistive currents above the system charging ampere level will not appreciably reduce the transient magnitude further. Normally, the weak link for 60 Hertz events is the surface area of insulators and bushings. However, higher frequency transients lower the impedance of air gap capacitive reactance, and double line to ground faults that breach the air gap may have been initiated by arcing spitting grounds. Before the charging amps



$$uf = 2.2 \times \frac{MVA}{1.5}$$

Notes:
Useful for determining charging amps for 480 volt power systems. Tests or manufacturers' data should be used for more refined *uf* values.

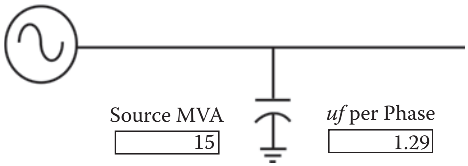
FIGURE 3.17
Typical 480 System Capacitive Microfarads

can be calculated, a microfarad capacitance value per phase needs to be determined. The amount of capacitance in the total system can be approximated from tables in various publications, manufacturer data, or by measuring the three-phase capacitance to ground with a capacitance meter during an outage with all respective loads, transformers, and buses included in the measurement. Low voltage capacitance meters will generally yield the same capacitance values as the higher voltage insulation power factor test sets. The result can be divided by 3 to approximate the per-phase capacitance.

A per-phase microfarad level of 2.2 and a charging current of 0.7 amps are typical for a 1500 kVA 480 volt three-phase transformer with connected loads, as indicated in Figure 3.16. This was determined by performing an applied ground test on a 480 system and measuring the capacitive current flow. Figure 3.17 estimates the charging microfarads per phase for a 2000 kVA 480 volt three-phase transformer with connected load at 2.9 microfarads per phase; the charging current would be around 0.9 amps.

A 4 kV three-phase 10 MVA transformer and connected loads will generally have around 0.86 microfarads of capacitance per phase or 2.4 amps of charging current as measured by a low voltage capacitance meter. The 4 kV system has a lower capacitance than the 480 volt system even though its MVA is over 6 times greater. The increased thickness of the 4 kV insulation reduces the microfarad value. Figure 3.18 estimates the per-phase capacitance for a 15 MVA 4 kV system as 1.29 microfarads per phase; the charging current would be approximately 3.6 amps.

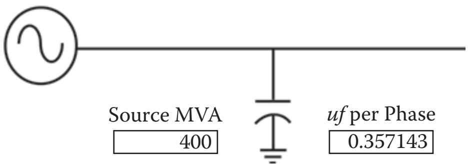
The microfarads for both two-pole and four-pole HP and LP 20 kV 280 MVA generator systems were each measured at approximately .25 microfarads per phase with a 10 kV power factor insulation test set. Again, the microfarad value is lower because of the increased thickness of the insulation system even though it is approximately 187 times higher in MVA than the 480 volt



$$uf = .86 \times \frac{MVA}{10}$$

Notes:
Useful for determining charging amps for 4 kV auxiliary systems. Tests or manufacturers' data should be used for more refined *uf* values.

FIGURE 3.18
Typical 4 kV System Capacitive Microfarads



$$uf = .25 \times \frac{MVA}{280}$$

Notes:
Useful for determining charging amps for generator systems. Tests or manufacturers' data should be used for more refined *uf* values.

FIGURE 3.19
Typical Generator System Capacitive Microfarads

system. Figure 3.19 estimates the per-phase capacitance of a 400 MVA generator system at about 0.357 microfarads. The charging current would be about 3.3 amps for the 280 MVA generators (including the isolated phase bus and connected transformer primary windings) and 4.7 amps with the 400 MVA generator. The estimates are more approximate for bulk power generators because their rated voltages typically range from 12 kV to 26 kV. However, the insulation thickness differences are somewhat offset because the charging current magnitudes increase as the voltage goes up.

As discussed earlier, ideally, the ground detector would be sized to provide a resistive current that equals the capacitive current that flows when one phase is 100% grounded. Accordingly, the total ground current would be the vector sum of the capacitive insulation system current and the resistive current from the ground detection scheme (90 degrees apart) or one of the currents multiplied by 1.414 if they are equal to each other.

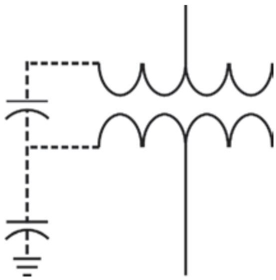


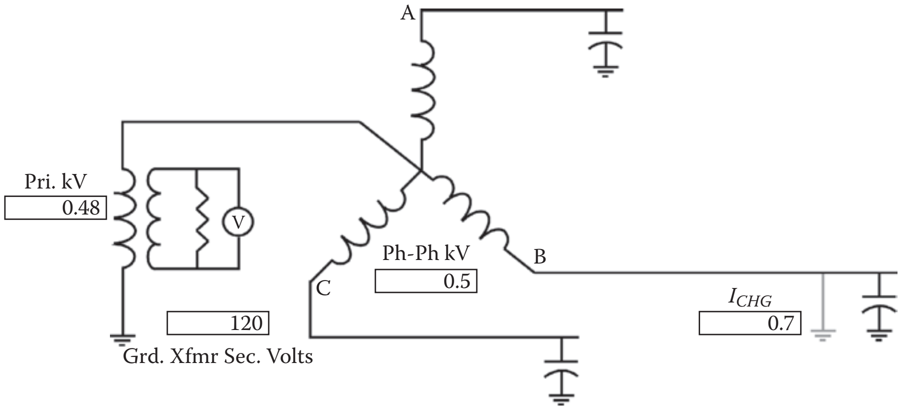
FIGURE 3.20
Primary to Secondary Capacitive Coupling

3.10.3 Primary to Secondary Capacitive Coupling

Stray capacitance is everywhere, and Figure 3.20 illustrates the stray capacitance between the primary and secondary windings of a power transformer and the stray capacitance between the secondary side insulation system and ground. The amount of inner winding capacitance can be reduced by installing a conductive shield between the primary and secondary windings (grounded at one location only), which is often included in generator step-up transformers. In the case of delta connected secondary windings that are floating or ungrounded, if only one phase is energized, a voltage divider circuit is formed between the stray internal transformer capacitance and the external insulation system secondary capacitance to ground. If the external stray capacitance is lower (higher impedance) because the secondary side circuit breaker is open, high voltages from the primary side can couple to the secondary side through this capacitance. There are cases where potential transformers installed on the secondary side failed from the high capacitive coupled phase-to-neutral voltage during single-phase switching. A properly designed ground detector will appear as a resistance in parallel with the secondary stray capacitance, reducing the secondary side impedance and forcing most of the primary side phase-to-neutral voltage to be dropped across the transformer internal capacitance. This phenomenon tends to be more associated with single-phase switching, circuit breaker pole disagreement, or blown fuses. When all three phases are energized, the capacitive current flows primarily between phases and higher magnitude capacitive coupled 60 Hertz voltages do not tend to occur.

3.10.4 Neutral Grounding

In Figure 3.21, the procedure for sizing the various components in a neutral transformer alarm-only ground detection scheme is illustrated. First, the capacitive charging amps are multiplied by the grounding transformer ratio to determine the amount of resistive current needed on the secondary side. Next, the phase-to-neutral voltage is derived and then divided by the



$$\text{Grd. Xfmr. Ratio} = \frac{\text{Pri. kV} \times 10^3}{\text{Rated Sec. Volts}}$$

$$100\%\ Grd.\ (V_{SEC}) = \frac{E_N}{Ratio} \quad \boxed{72.168}$$

$$E_N = \frac{\text{Ph-Ph kV} \times 10^3}{\sqrt{3}}$$

$$R_{SEC} = \frac{V_{SEC}}{I_{SEC}} \quad \boxed{25.775}$$

$$I_{SEC} = I_{CHG} \times Ratio$$

$$Minimum\ Grd.\ Xfmr\ VA = Pri.\ kV \times 10^3 \times I_{CHG} \quad \boxed{336}$$

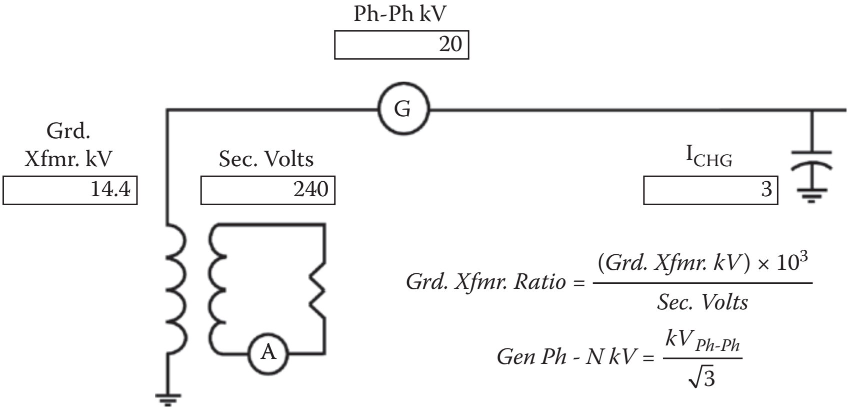
$$Minimum\ Sec.\ Resistor\ Watts = \frac{V^2_{SEC}}{R_{SEC}} \quad \boxed{202.073}$$

Notes:
The ratings given are continuous for alarm only ground detector schemes.

FIGURE 3.21
Neutral Grounding Transformer Sizing

grounding transformer ratio to determine the secondary voltage for a 100% ground condition. The resistor ohmic value can now be determined by dividing the 100% ground secondary voltage by the desired current. The minimum resistor watt rating can be determined by dividing the 100% ground secondary voltage squared by the resistor's ohmic value. The minimum VA of the grounding transformer can be calculated by multiplying the primary charging amps by the primary voltage rating of the transformer. The primary voltage rating of the grounding transformer should be, at minimum, equal to or greater than the system phase-to-neutral voltage. A secondary voltmeter will read zero if no ground is present. A voltage relay should be installed in parallel with the secondary resistor to alarm for ground conditions. Normal practice is to set the minimum pickup point at 10% of the 100% phase-to-neutral voltage on the secondary side and alarm to 1.0 seconds. In general, resistors run hot, and high temperature insulation wiring may be required for the resistor terminations.

Figure 3.22 shows the same procedure for sizing the grounding components for generators. The only difference is that the grounding transformer



$$Grd.\ Xfmr.\ Ratio = \frac{(Grd.\ Xfmr.\ kV) \times 10^3}{Sec.\ Volts}$$

$$Gen\ Ph\text{-}N\ kV = \frac{kV_{Ph\text{-}Ph}}{\sqrt{3}}$$

$Secondary\ Amps\ (I_{SEC}) = I_{CHG} \times Ratio$	180
$100\%\ Grd.\ Sec.\ Volts\ (V_{SEC}) = \dfrac{kV_{Ph\text{-}N} \times 10^3}{Ratio}$	192.45
$Secondary\ Ohms\ (R_{SEC}) = \dfrac{V_{SEC}}{I_{SEC}}$	1.069
$Max.\ Grd.\ Xfmr.\ VA = kV_{PRI} \times 10^3 \times I_{CHG}$	43200
$Maximum\ Secondary\ Resistor\ Watts = \dfrac{V^2_{SEC}}{R_{SEC}}$	34641.021

Notes:
For ground schemes that trip in 1.0 seconds, a 10-second short time rating for determining the VA size of the grounding transformer and the secondary resistor wattage should provide adequate thermal margins.

FIGURE 3.22
Generator Neutral Grounding Transformer Sizing

and resistor do not need to carry the current continuously because the generator stator ground tripping relay will de-energize the system in a short time. At minimum, a thermal margin of 10 should be applied. That is, the apparatus should be capable of carrying 100% ground fault current for a period that is 10 times longer in duration than the 100% ground time delay of the generator stator ground tripping relay.

An I^2T calculation can be used to determine the short time current carrying capabilities of the grounding scheme components as presented in Figure 3.23. Assuming that the manufacturer specified a short time thermal rating of 100 amps for 40 seconds, a new rating could be calculated for the actual ground fault current level of 180 amps. First, square the 100 amps and then multiply it by 40 to get an I squared T value of 400,000. Then, apply the expression shown in Figure 3.23 to convert the 100-amp short time thermal

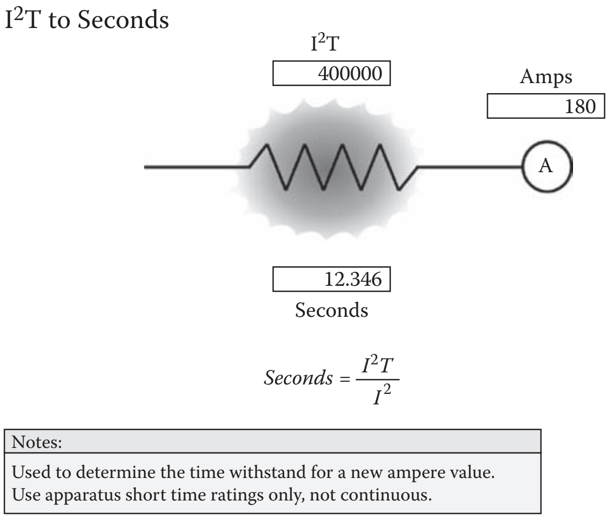


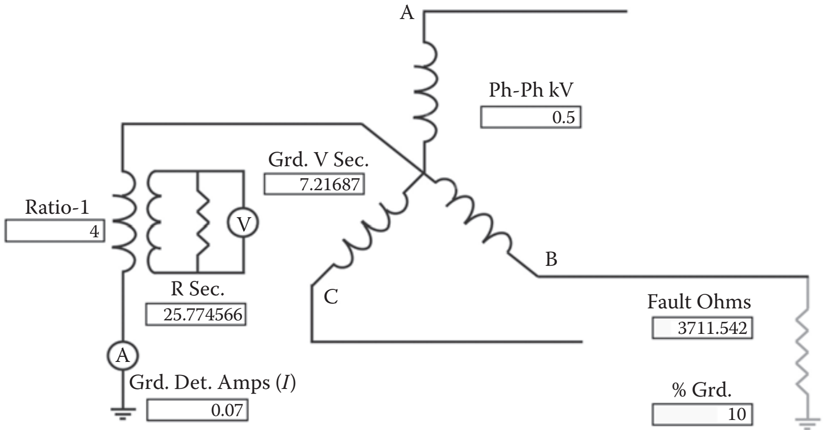
FIGURE 3.23
I^2T Calculation

rating to an equivalent 180-amp short time thermal rating. In this case, the apparatus should be able to carry 180 amps for 12 seconds without damage.

Figure 3.24 covers a calculation procedure for determining the ground detector primary current, fault ohms, and percent ground for different values of secondary voltages to assess the severity of the fault. The percent ground is determined by dividing the actual secondary voltage by the 100% ground secondary voltage and multiplying by 100. The primary 100% ground detector current will be reduced by the same percentage, and the number of ground fault ohms necessary to limit the ground current to that value can then be determined. The fault ohms can be calculated by subtracting out the reflected secondary to primary ohms from the total ohms required to limit the ground detector primary current to the determined value; the remaining amount would represent the fault ohms.

3.10.5 Grounded Wye–Broken Delta Grounding

Because delta-fed systems are not equipped with neutral points, a different approach is needed for ground detection. The most common method is to install a grounded wye–broken delta ground detector scheme. This scheme and the associated calculations for sizing the transformers and secondary resistors are illustrated in Figure 3.25. With no system ground present, voltage will not be developed on the secondary side. If you trace the direction of phase-to-phase current flow in the primary windings, it can be seen that the two developed secondary voltages oppose each other. When a 100% system ground fault occurs, it is equivalent to shorting out



$$E_N = \frac{Ph\text{-}Ph\ kV \times 10^3}{\sqrt{3}} \qquad \%\ \text{Grd.} = \frac{Grd.\ V\ Sec.}{(E_N/Ratio)} \times 100 \qquad R_{PRI} = R_{SEC} \times Ratio^2$$

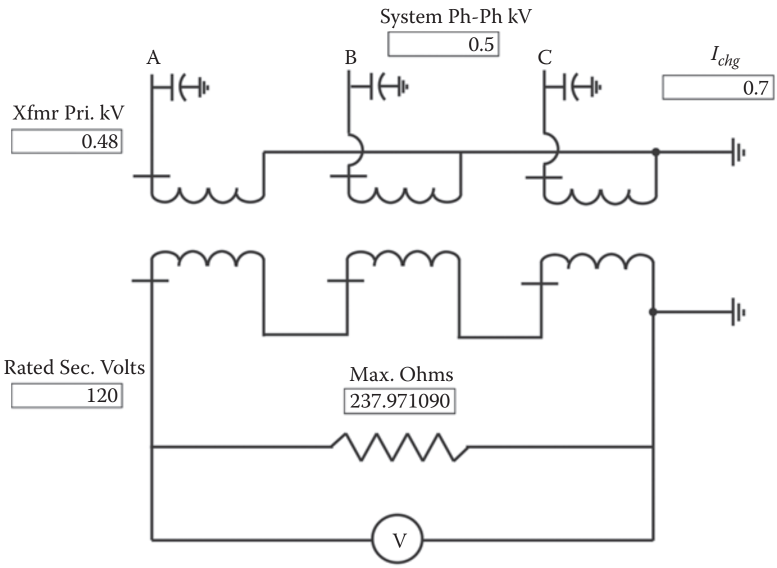
$$Ground\ Detector\ Amps = \left(\frac{E_N}{R_{PRI}}\right) \times \left(\frac{\%\ Grd.}{100}\right) \qquad Fault\ Ohms = \frac{E_N}{I} - R_{PRI}$$

Notes:
Ground detector amps does not include the capacitive charging current that will also flow to the ground fault.

FIGURE 3.24
Neutral Ground Detector Fault Ohms

one of three transformers. This, in effect, eliminates the opposing voltage for two of the three phase-to-phase combinations and allows a voltage to develop on the secondary side. Because of the connections, the two secondary phase-to-phase voltages end up being 60 degrees apart and, consequently, will develop a total secondary voltage that is greater by the square root of 3 or 1.732 times the secondary value for one of the phase-to-phase voltages. A voltage relay should be installed in parallel with the secondary resistor to alarm for ground conditions. Normal practice is to set the relay minimum pickup point at 10% of the 100% system ground secondary voltage with a time delay of 1.0 second.

Because the three transformers are connected in series on the secondary side, current will flow equally through all three secondary windings. Therefore, each winding or phase will contribute equal primary current to a ground fault condition. Accordingly, in the calculation in Figure 3.25, the desired total primary charging amps are divided by 3 and then multiplied by the winding ratio to determine the desired secondary current. The maximum ohmic value for the secondary resistor can then be determined by dividing the 100% ground fault secondary voltage by the desired secondary current. Again, the 100% ground fault voltage is the phase-to-phase system voltage divided by the transformer ratio times 1.732, or 216.5 volts, as indicated in the figure. The minimum VA for each transformer can be



$$Ratio = \frac{Xfmr\ kV \times 10^3}{Xfmr\ Sec.\ Volts}$$

$$100\%\ Grd\ (V_{sec}) = \frac{Sys.\ kV \times 10^3}{Ratio} \times \sqrt{3} \quad \boxed{216.506351}$$

$$I_{sec} = \frac{I_{chg}}{3} \times Ratio$$

$$Min.\ VA/Ph = \frac{I_{chg}}{3} \times Xfmr\ kV \times 10^3 \quad \boxed{112}$$

$$Maximum\ Ohms = \frac{V_{sec}}{I_{sec}}$$

$$Minimum\ Watts = \frac{V_{sec}^{\ 2}}{Ohms} \quad \boxed{202.072594}$$

Notes:
All ratings are for continuous operation for alarm only ground detector schemes.

FIGURE 3.25
Grounded Wye–Broken Delta Ground Detector Sizing

determined by dividing the primary charging current by 3 and multiplying the result times the rated primary voltage of each transformer. Squaring the 100% ground secondary voltage and dividing it by the secondary resistor's ohmic value will develop the minimum wattage for the resistor.

Figures 3.26 and 3.27 illustrate the current flows and phasor relationships for grounded wye–broken delta ground detectors and ground banks. As you can see, the developed secondary voltage ends up being in phase with the faulted phase-to-neutral voltage.

Figure 3.28 illustrates a calculation procedure for determining the amount of ground detector current, fault ohms, and percent ground for different values of secondary voltages to assess the severity of the fault. If you compare the 10% ground fault ohms to Figure 3.24 for the neutral grounding scheme, you will find that they are the same. The percent ground is determined by dividing the actual secondary voltage by the 100% ground secondary voltage and multiplying by 100. The primary ground detector current

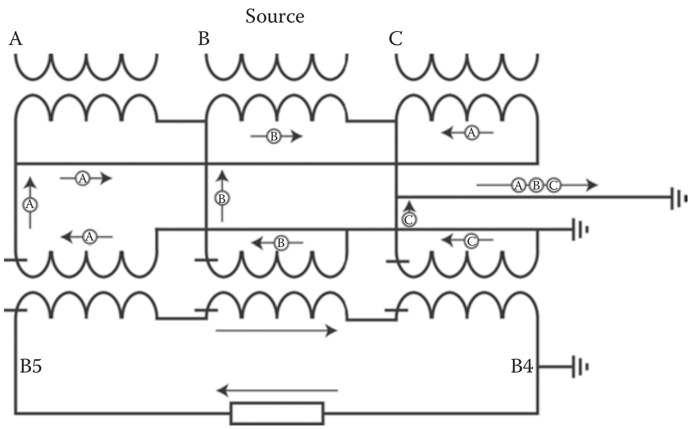


FIGURE 3.26
Grounded Wye–Broken Delta Ground Detector Current Flows

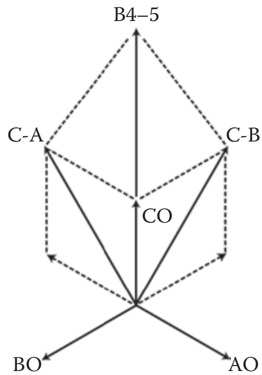


FIGURE 3.27
Grounded Wye–Broken Delta Ground Detector Phasors

will be reduced by the same percentage. The amount of fault ohms necessary to limit the ground to that amount of current can then be determined by dividing the phase-to-neutral voltage by the ground detector current and subtracting out the reflected ground detector bank primary ohms. In this case, the single transformer reflected secondary to primary ohms needs to be divided by 9 to account for the impact of all three windings.

Wye/delta transformer windings should not be energized with the delta open or broken. A transformer with a broken or open delta can become electrically unstable (depending on circuit impedance parameters), causing very high currents to flow. This condition is known as neutral instability, or three-phase ferroresonance. The individual transformers can go in and out of saturation in a three-phase fashion, causing very high currents to flow into the bank. Installing the secondary resistor helps to close the delta or

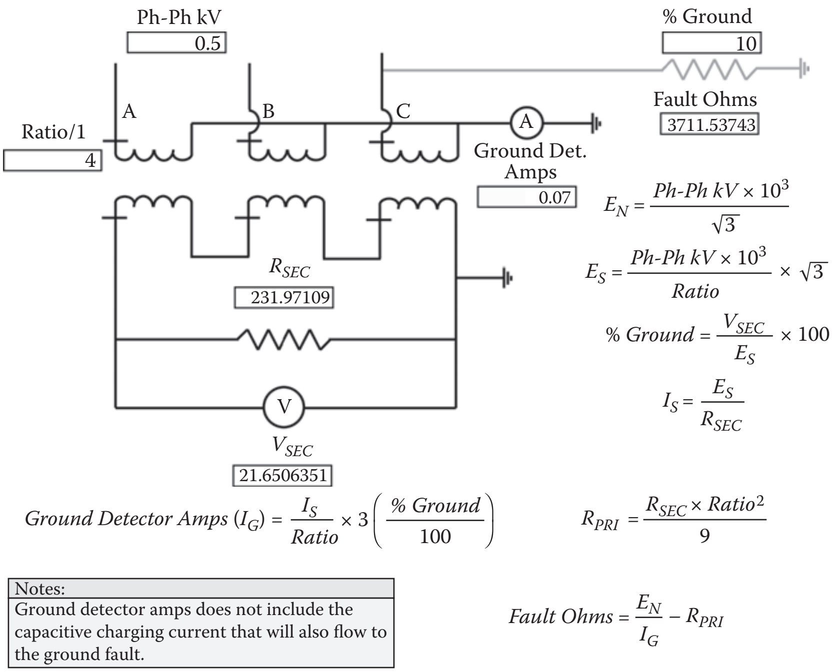
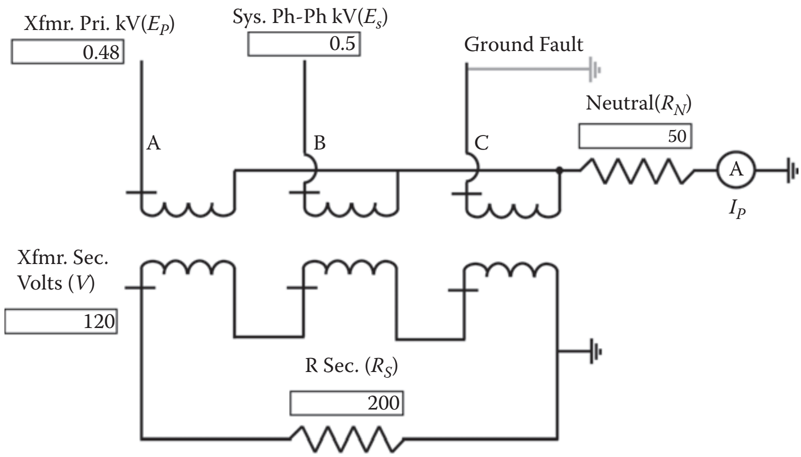


FIGURE 3.28
Grounded Wye–Broken Delta Ground Detector % Ground

stabilize the connection. With the secondary resistor, instability is usually not a problem, but as a precaution, primary fuses should always be installed in this type of connection. Another problem is that blown fuses can cause voltages to develop on the secondary side, which could actuate the relay. For this reason, tripping with this type of scheme is generally not recommended. Also, blown fuses can be hard to detect because this winding configuration also tends to try to reproduce the missing voltage. Its ability to do so is dependent on the impedance parameters of the circuit. The most effective way to quickly detect blown primary fuses is to install fuses equipped with plungers that will actuate micro switch alarms when they blow.

However, if fuse blowing turns out to be a problem, indicating possible instability, a resistor can be installed in the neutral to prevent the transformers from saturating. Figure 3.29 shows a procedure for calculating the impact of installing a neutral resistor. In this example, a 50 ohm resistor is connected between the ground detector neutral point and ground, and the secondary resistor is reduced from 232 ohms to 200 ohms to counter the effect of the neutral resistor and still maintain approximately 0.7 amps primary as presented in Figure 3.25.

First, the neutral ohms need to be reflected to the secondary side. The neutral ohms are multiplied by 3 to account for infeed or distribution of



$$\text{Xfmr. Ratio } (N) = \frac{(E_P \times 10^3)}{V}$$

$$\text{100\% Ground Secondary Volts } (V_G) = \left(\frac{(E_S \times 10^3)}{V}\right) \times \sqrt{3} \quad \boxed{216.506}$$

$$\text{R Secondary Total } (R_T) = \left(\frac{9R_N}{N^2}\right) + R_S \quad \boxed{228.125}$$

$$\text{Primary Amps } (I_P) = \left(\frac{V_G}{R_T N}\right) \times 3 \quad \boxed{0.711802}$$

$$\text{Z Phase - Neutral} = \frac{E_S \times 10^3}{\sqrt{3}\, I_P} \quad \boxed{405.556}$$

Notes:
If the scheme blows fuses, instability may be the problem and neutral resistance may be required.

FIGURE 3.29
Grounded Wye–Broken Delta Neutral Ohms

one-third of the current in each phase and then by 3 again to account for the reflected ohms in each of the three secondary windings for a total factor of 9. Then, the adjusted ohms can be reflected to the secondary side and added to the secondary resistor ohms for a total ohmic value. The total primary amps can now be determined by dividing the 100% ground secondary voltage by the total secondary resistance times the transformer turns ratio and then multiplying the result by 3 to account for the contribution from each phase.

3.11 Transformer High-Speed Protection

In addition to the overcurrent protection presented earlier, oil-filled transformers that are 5 MVA and larger are usually equipped with sudden pressure relays and differential protection. Both devices will detect internal faults very quickly and electrically isolate the transformer to limit internal damage and contain the fault within the tank to mitigate explosions and fire hazards to personnel and adjacent equipment. Two types of sudden pressure relays are commercially available: a gas type for nitrogen blanketed transformers and an oil or liquid type for conservator tank transformers.

3.11.1 Current Differential Protection

A basic differential scheme for one phase only is illustrated in Figure 3.30. The dash lines in the primary circuit represent the electrical apparatus being protected, which could be a transformer, motor, generator, bus, or feeder. Basically, the current "in" needs to equal the current "out" or a fault is indicated. The arrows in the CT secondary circuit denote the relative direction of current flow during normal load flows or through fault conditions. The currents will circulate between the two CTs and no current will flow in the operating coil as long as the secondary currents are balanced. If an internal fault occurs inside the CT boundaries, the load side secondary current will either reverse in direction (multiple sources) or cease to exist if there are no other sources. In either case, current will now be forced to flow through the operating coil because the load side CT will either produce a current in the opposite direction or become a high impedance in the absence of a corresponding amount of primary current. If the operating coil current is high enough, the relay will actuate to isolate the faulted area.

Current differential protection offers a couple of advantages: high-speed tripping because they do not need to coordinate with downstream devices and they can be set well below load current values. The biggest area of concern is false operations from CT error currents. The error currents can be quite significant during through fault (high current) conditions that may saturate the CTs unequally and also have a direct current (DC) component from asymmetrical current flow. To counter this problem, the relays are designed with slope percentages that typically range from 10% to 25% for

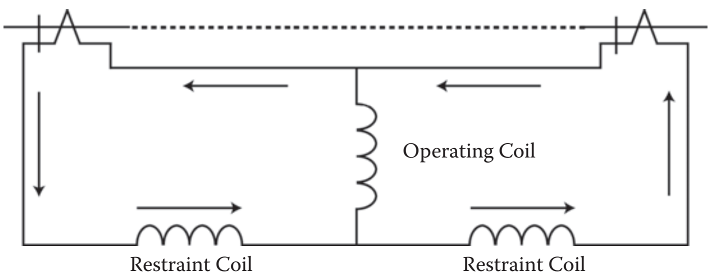
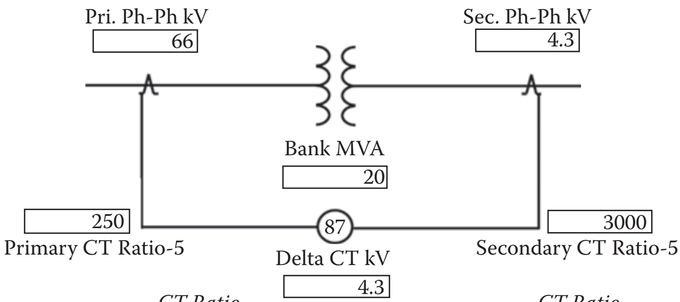


FIGURE 3.30
Current Differential Protection



$$CT_r\ Pri. = \frac{CT\ Ratio}{5} \qquad CT_r\ Sec. = \frac{CT\ Ratio}{5}$$

$$Pri.\ FLA = \frac{MVA \times 10^6}{\sqrt{3}\ Ph\text{-}Ph\ kV \times 10^3} \qquad Bank\ Ratio = \frac{Pri.\ Ph\text{-}Ph\ kV}{Sec.\ Ph\text{-}Ph\ kV}$$

$$Bank\ Sec.\ FLA = Pri.\ FLA\ (Ratio)$$

$$Wye\ CT\ Sec.\ Amps = \frac{FLA}{CT_r} \quad \boxed{3.499093}$$

$$Delta\ CT\ Sec.\ Amps = \left(\frac{FLA}{CT_r}\right) \times \sqrt{3} \quad \boxed{7.751938}$$

$$Ideal\ Tap\ Ratio = \frac{>CT\ Sec.\ Amps}{<CT\ Sec.\ Amps} \quad \boxed{2.215414}$$

$$Primary\ Tap \quad \boxed{2.256915}$$

$$Secondary\ Tap \quad \boxed{5}$$

Notes:
For transformer differential schemes using delta CTs on one side and wye CTs on the other side.

FIGURE 3.31
Transformer Differential Relay Taps

generators, motors, buses, and feeders, and 20% to 60% for transformers. Slope is the ratio of one or two restraint coil currents to the operating coil current, and the actual calculation details vary between manufacturers. Some designs offer variable slope with the slope percentage increasing as the current levels increase. The advantage of slope is that it takes more current to actuate when the currents are higher, thereby providing a greater margin for error currents.

Transformer current differential protection must accommodate magnetizing inrush current conditions, which can get quite high depending on the position of the sine wave, the circuit resistive ohms, the short circuit duty of the power system, MVA of the bank, and the amount of residual magnetism in the core iron, that is, design of the magnetic circuit and the iron lamination material properties or alloy details. Excluding residual magnetism, maximum inrush current occurs when the sine wave is at zero crossing because the rate of change and associated self flux and inductive reactance will be lower. RMS peaks as high as 20 times full load are possible, depending on the foregoing conditions. Much of the inrush current decays in the first few cycles, but the remaining level may take several seconds to dissipate. Initially, it looks like 60 Hz half-wave rectification (120 Hz to a filter) until the circuit L/R decrement allows the negative or opposite-going sine wave to produce current flow. Transformer differential relays are normally desensitized to 120 Hz differential currents to prevent false operation from magnetizing inrush operations.

Figure 3.31 shows a typical nondigital transformer differential scheme that applies wye CTs on the primary side and delta connected CTs on the secondary side. Because a delta-wye transformation causes a 30-degree phase shift between the transformer's primary and secondary phase-to-neutral voltages, the CT secondary currents will not be in phase. In this case, applying delta CTs on the wye or secondary side will bring the secondary currents back into phase because the delta connection will shift the secondary currents by 30 degrees. Transformer differential relays are equipped with ratio tap blocks to compensate for the different current magnitudes on each side of the transformer. Current differences between the primary and secondary sides of the transformer that cannot be balanced out by the CT ratios and relay taps will flow through the operating coils of the relay. If this current is high enough (indicating an internal fault or incorrect taps), the relay will operate to electrically isolate the transformer. To select the taps, one must first determine the CT secondary full load amps on each side of the transformer. The current inside the delta CTs should be multiplied by the square root of 3 or 1.732 to account for the current contributions from the other CTs. Then, an ideal ratio can be determined by dividing the larger CT secondary current by the smaller CT secondary current. Finally, the closest ratio can be selected from the available relay taps. In this case, a 5.0 tap on the secondary side and a 2.3 tap on the primary side will closely match the ideal ratio. This is not intended to be a full explanation of the application of transformer differential relaying—which can be quite complex when considering unbalanced faults—but only an aid on how to determine the closest tap ratio for the relays. The newer digital relays can accept wye-wye CTs and account for differences through software programming.

3.12 Bus Transfer Schemes

Figure 3.32 illustrates a typical generating station one-line drawing. When automatic systems trip the unit off-line because of process problems,

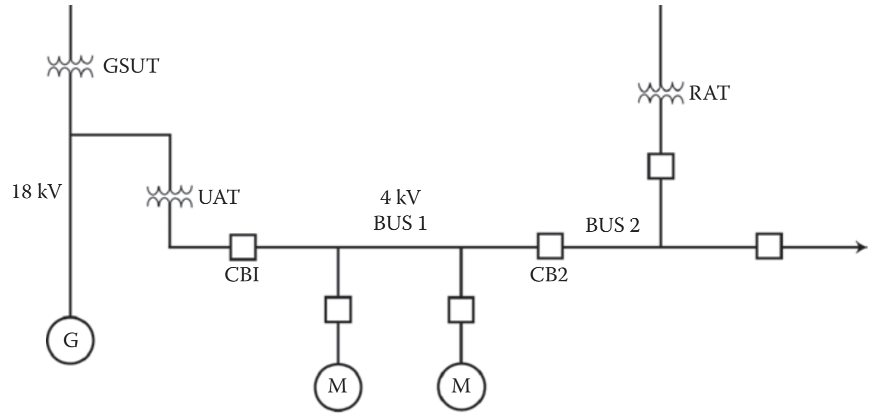
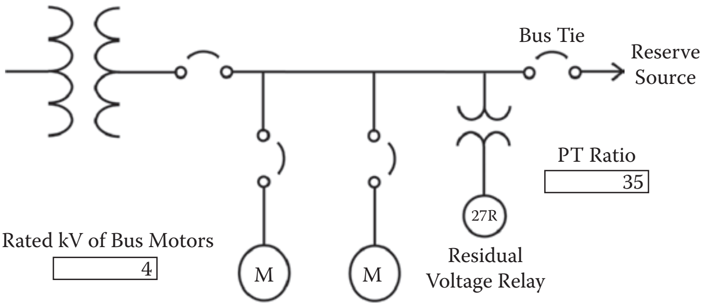


FIGURE 3.32
Typical Generating Station One-Line

CB1 trips open and CB2 will close to repower 4 kV bus 1 after all of the required supervisory permissive or logic functions are met. This section will describe the reasons for each logic or contact permissive in automatic bus transfer schemes.

Residual voltage relays are normally applied to supervise or block automatic bus transfers until the voltages are at a safe level. These relays prevent motor damage during automatic bus transfer operations from excessive voltages that can over flux motor core iron and also cause high stator currents resulting in increased electromechanical forces on the windings. When a bus with motor loads is de-energized, the motors act like generators and produce residual voltages for a short time as a result of the trapped magnetic flux in the iron cores at the time of de-energization. If bus tie breaker CB2 closes before the residual voltage has a chance to dissipate to a safe level, and if the vector sum of the motor residual voltage and the new source voltage exceeds 1.33 per unit or 133%, the motors can be damaged or the remaining life reduced. Because the duration is short (usually around 1.0 seconds or less) and generally beneath the core iron overexcitation time withstands, the main concern is that the electromechanical forces could be damaging to motors in a reduced speed starting current mode of operation.

Figure 3.33 presents a suggested residual voltage relay set point calculation that will prevent damage to motors during automatic bus transfer drop/pickup operations. Basically, the relay is set for .33 per unit of the motor nameplate or rated voltage. When the set point value is reached, the automatic circuitry will dispatch a close signal to the bus tie breaker. This will prevent the vector sum of residual and new source voltages from exceeding 1.33 per unit. This setting has extra margin because the residual voltage will be below .33 per unit by the time bus tie breaker CB2 contacts actually close.



$$27\ R\ Dropout\ (kV_D) = 0.33 \times Mtr.\ Rated\ kV \quad \boxed{1.32}$$

$$27\ R\ Secondary\ Volt\ Dropout = \frac{kV_D \times 10^3}{PT\ Ratio} \quad \boxed{37.714286}$$

Notes:
Motors can withstand 1.33 per unit. This setting is conservative since the residual voltage will be less than 0.33 per unit by the time the bus tie breaker closes and completes the transfer.

FIGURE 3.33
Residual Voltage Relay Settings

The residual voltage decay time will vary depending on the mix of motors, that is, synchronous, induction, number of poles, and combined inertia. When the bus is de-energized, the residual voltage frequency also decays as the motors slow down in speed. Accordingly, residual voltage relays should be designed in a way that the frequency decay will not impact the set point or actuation of the relay. This can be accomplished with electromechanical coils by feeding them through bridge rectifiers.

Many older generating stations have a number of disadvantages in the design of their bus transfer schemes in addition to not monitoring residual voltage levels. Among the many bus transfer operating considerations in fossil plants is a particular concern about maintaining the fans after unit tripping to ensure that trapped combustible gases are quickly blown out of the boiler to mitigate the possibility of explosions. Because of this concern, there is a design motivation to transfer as quickly as possible. A suggested DC elementary design for bus transfer schemes is illustrated in Figure 3.34 that resolves the disadvantages of the older schemes. The author designed the scheme for a major utility many years ago after a severe bus fault and resulting fire significantly damaged about a dozen breakers and cubicles in a 4 kV switchgear room. An investigation disclosed that the bus transfer scheme failed to coordinate with overcurrent relays that should have prevented a transfer into the faulted bus. The older scheme tripped the auxiliary transformer breaker CB1 on undervoltage (faults depress the voltage) with a short time delay and then closed the bus tie breaker CB2 energizing the fault a second time from bus 2 or the reserve before the overcurrent relays could time out and block

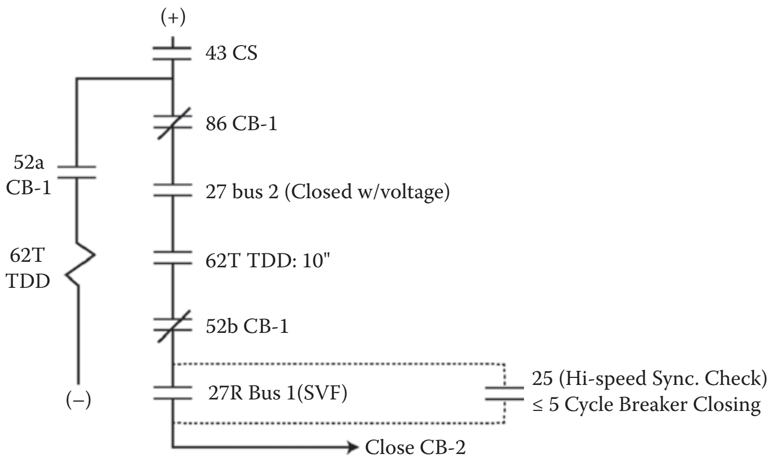


FIGURE 3.34
Bus Transfer Elementary

the transfer. Second energizations cause significantly more damage because the electrical apparatus has stored heat from the first event and then gets hit again with the short circuit current heating starting at a higher temperature.

In reference to the Figure 3.34, the existing schemes were already equipped with 43 transfer switches to allow operations to take the automatic bus transfer in and out of service, 86 lockout relay contacts to block transfers into faulted buses, and 27 undervoltage relay contacts on bus 2 to ensure that the reserve or new bus voltages are adequate. Three new contacts were added to the existing schemes: the *62 TDD* (one shot timer that is armed when the auxiliary transformer breaker CB1 is closed), which allows 10 seconds for transfers to occur before removing the automatic bus transfer from service to prevent automatic transfers when plant operators reset 86 lockout relays; the *52b* (auxiliary transformer breaker CB1 open), which allows fast transfers to coordinate with overcurrent relays (if fault relays open breaker CB1, bus transfers will be automatically blocked); and the *27R* residual voltage relay, which dispatches a close signal to bus tie breaker CB2 if the residual voltage is in a safe range. The 25 high-speed sync check relay is optional where transfers faster than 1.0 second are desired and if tie breaker CB2 closes in 5 cycles or less (some breakers can take 20 cycles or more to close). Special sync check relays are available to measure the angular differences between the buses before the event and, if the range is acceptable, the 25 relay assumes that the angles cannot get too far out before the fast breaker contacts close which prevents the vector sum from exceeding 1.33 or 133%. The sync check scheme still needs to be backed up by a residual voltage transfer relay in case the angles are not acceptable.

3.13 Bibliography

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4

Generator Protection

Considering the large capital investment and the numerous possibilities for electrical system disturbances, control instrumentation malfunctions, and operator errors that can allow generators to operate outside of their original design specifications, it makes good business sense to apply protective relays that can prevent generator damage during abnormal operating conditions. This chapter will cover the gathering of information needed to calculate protective relay settings, the setting calculations for the various protective functions, typical generator/turbine withstand times for abnormal operating conditions, and the math associated with various types of impedance elements.

4.1 Generator Relay Data

A good starting point is to compile the data needed for setting the various generator protective functions. Figures 4.1, 4.2, and 4.3 provide examples of organizing and massaging or converting the information to a more useful form for generators, step-up transformers, and their associated electrical systems. The information is for a 578.6 megavolt-amp (MVA), 24 kilovolt (kV) generator that is connected to the 765 kV bulk power transmission system. Organizing the data in this manner will save significant time in developing and documenting the basis for the relay settings.

The top half of Figure 4.1 shows the generator data needed for the relay settings, including generator nameplate data; the direct axis saturated subtransient, transient, and the synchronous per-unit reactances; and the various primary and secondary instrument transformer ratings. With the exception of converting primary ohms to secondary or relay ohms (as shown in Figures 4.4 and 4.5), the MVA and per-unit conversions were covered in Chapter 2 and will not be discussed further here. The bottom half of Figure 4.1 provides nominal currents, instrument transformer ratios, and various reactance ohms (not per unit) that will be used to develop the settings for the backup impedance, loss-of-excitation, and out-of-step relay functions.

Figure 4.2 presents the step-up transformer secondary or relay ohms for the backup impedance and out-of-step relay functions. The transformer

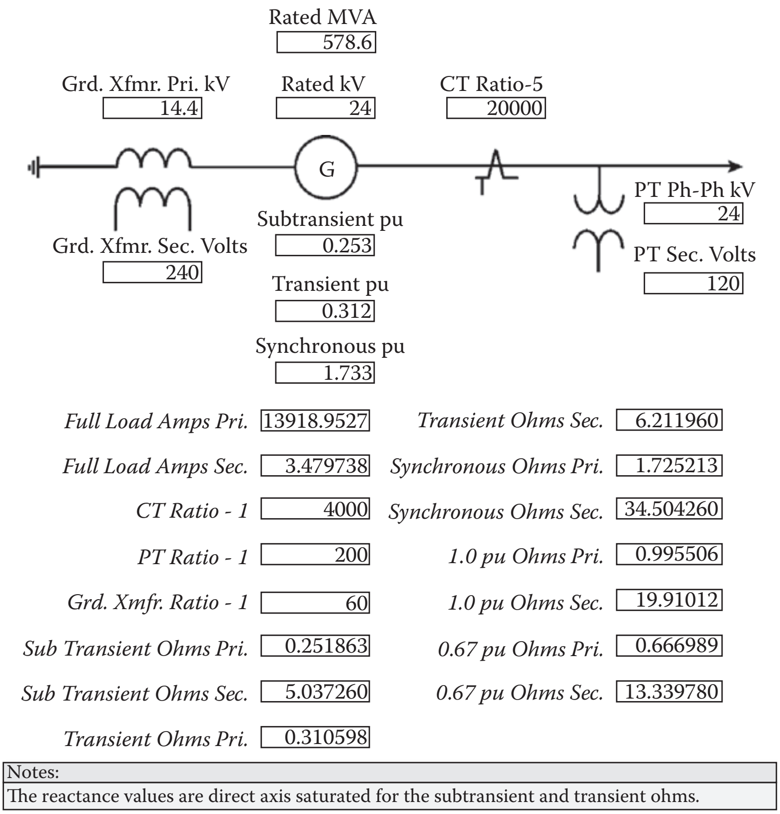
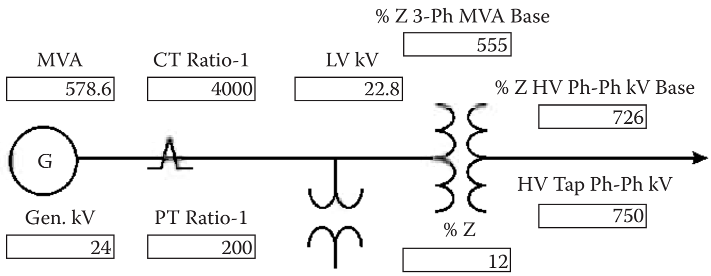


FIGURE 4.1
Generator Data

per-unit base impedance at 555 MVA needs to be converted to the generator base of 578.6 and corrected for voltage differences on the generator side of the transformer and tap differences on the high voltage side of the transformer. With the exception of secondary or relay ohms, the per-unit MVA conversions and corrections have already been discussed.

Figure 4.3 develops the high voltage switchyard secondary or relay ohms for the generator out-of-step function. Normally, this calculation would not include the short circuit contribution from the generator. First, the system kV ohms and volt-amps (VA) are determined, then, the generator side amps and ohms are calculated, and finally, the secondary or relay ohms that represent the high voltage electrical system are developed. The system short circuit angle is not used in the calculation, but is needed for setting the out-of-step protective relay function.

Figure 4.4 presents the expression for calculating secondary or relay ohms. The converse calculation in Figure 4.5 is used to convert relay ohms to primary side ohms.



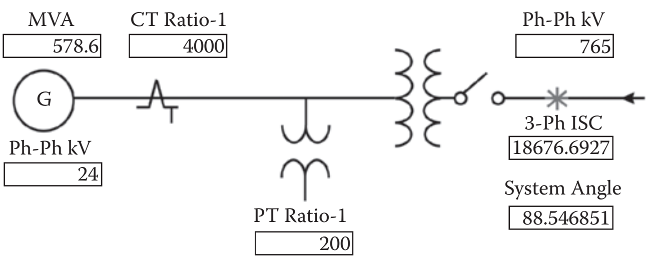
Generator Base Corrected pu Z 0.105795

Generator kV Ohms Primary 0.105320

Generator kV Secondary Ohms 2.106400

Notes:
Transformer impedance corrected to generated rated voltage and generator base MVA.

FIGURE 4.2
Transformer Data



$$\textit{System kV Ohms} = \frac{\textit{Ph-Ph kV} \times 10^3}{\sqrt{3}\ \textit{ISC}} \qquad \boxed{23.648349}$$

$$VA = \textit{Ph-Ph kV} \times 10^3 \times \textit{ISC} \times \sqrt{3}$$

$$V_G = \textit{Gen. Ph-Ph kV} \times 10^3$$

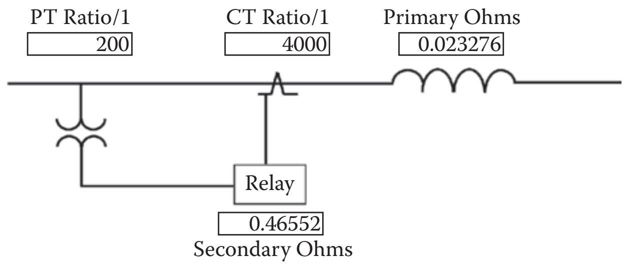
$$\textit{Gen. kV Amps}\ (I_G) = \frac{VA}{V_G \times \sqrt{3}}$$

$$\textit{Gen. kV Primary Ohms}\ (Z_G) = \frac{V_G}{I_G \times \sqrt{3}} \qquad \boxed{0.023276}$$

$$\textit{Gen. kV Secondary Ohms} = \frac{\textit{CT Ratio}}{\textit{PT Ratio}} \times Z_G \qquad \boxed{0.46552}$$

Notes:
The system 3-Ph ISC would not normally include the contribution from the generating unit under study.

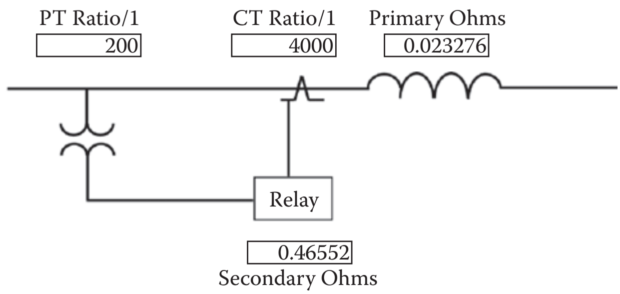
FIGURE 4.3
System Data



$$Z_{SEC} = \frac{CT\ Ratio}{PT\ Ratio} \times Z_{PRI}$$

Notes:
Z_{SEC} is the reflected primary ohms that the relay will measure.

FIGURE 4.4
Primary to Relay Ohms



$$Z_{PRI} = \frac{PT\ Ratio}{CT\ Ratio} \times Z_{SEC}$$

Notes:
Z_{PRI} is the reflected relay or secondary ohms to the primary side.

FIGURE 4.5
Relay Ohms to Primary Ohms

4.2 High Voltage Switchyard Configurations

Before delving into the generator protective functions, a review of the associated high voltage switchyards might be appropriate. Figures 4.6, 4.7, and 4.8 illustrate the more common switchyard configurations for handling two lines and one generating unit. In all three configurations, the opening of line breakers to clear faults increases the circuit X_L and momentarily reduces the power transfer capability on the remaining line until the power angle changes, as the unit accelerates, to match the output of the turbine.

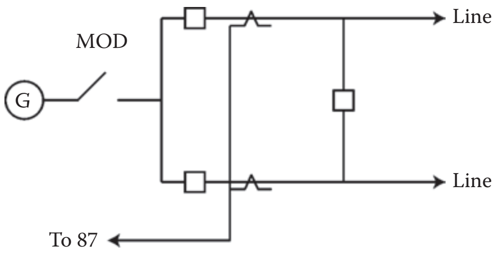


FIGURE 4.6
Ring Bus Configuration

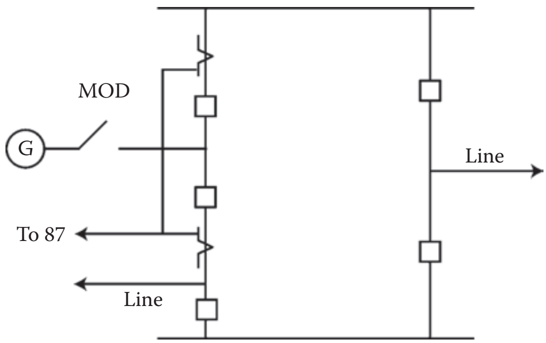


FIGURE 4.7
Breaker and a Half Configuration

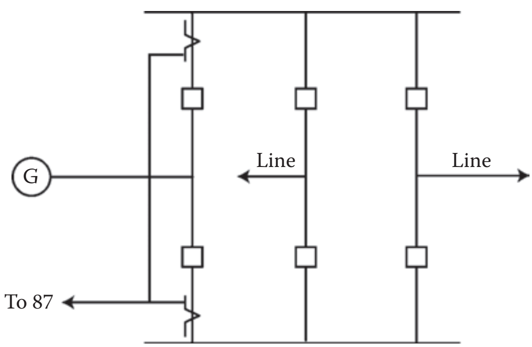


FIGURE 4.8
Double Breaker Double Bus

The Figure 4.6 ring bus configuration is the simplest and least costly. It also has the lowest maintenance costs and exposure to failures because there are fewer components. As the figure shows, only three breakers are required for one generating unit and two lines. Because each element (unit or line) has two breakers, the opening of one breaker does not interrupt power flows.

The generating unit position is equipped with a motor operated disconnect (MOD) that can be opened after the unit is taken off-line, permitting the reclosure of the unit breakers to improve the integrity of the ring bus. The 87 differential elements could be for the line from the generator step-up transformer (GSUT) to the switchyard but may also overlap the GSUT to provide transformer protection and, more commonly, will also overlap the generator to back up the generator protection. Schemes that include the generator are called overall *differential* or *unit differential.* With overall or unit differential, current transformers (CTs) are normally applied on the auxiliary transformer primary side to balance out any auxiliary load current. In all cases, the 87 differential protection must remain in-service when the unit is off-line (unless both unit breakers are open) because it now provides high voltage switchyard bus differential protection for the two unit breakers and the conductors between the breakers and the open MOD. The main disadvantage of a ring bus configuration is if one breaker is out-of-service for maintenance, a single line fault could interrupt power flow to the other line. Separate bus differential relays are not required, as the unit and line protection overlaps and protects the bus sections.

Figure 4.7 illustrates a breaker and a half configuration. Although this design requires five breakers for one generating unit and two lines, it provides greater electrical system security. This configuration has top and bottom buses that are usually protected by high impedance bus differential schemes. High impedance differential schemes are favored on large buses (multiple lines) to mitigate false operations from error currents associated with unequal CT loading and performance by forcing more of the false differential to flow in the CT circuit and less in the relay. The generating unit position is equipped with an MOD that can be opened after the unit is taken off-line, permitting the reclosure of the unit breakers to improve the integrity of the switchyard. As with the ring bus configuration, the 87 differential elements must remain in-service when the unit is off-line and the unit breakers are closed because it now provides high voltage switchyard bus differential protection for the breakers and for the conductors between the breakers and the open MOD. A second generating unit or a third line can be accommodated with the addition of only one more breaker.

Figure 4.8 displays a double breaker double bus configuration. In this example, six breakers are required for two lines and one generating unit. This provides the highest level of reliability. If a breaker is out for maintenance, a fault on a transmission line will not prevent power flow from the generating unit to the unfaulted line. Each bus section, top and bottom, would normally be protected with a high impedance bus differential scheme. The MOD is not required, as the unit breakers can remain open when the unit is off-line. The addition of another line or generating unit would require two breakers.

4.3 High Voltage Switchyard Protection Concerns

There are a number of concerns with the protection of generating station high voltage switchyards. The main concerns are the clearing of electrical system faults before the unit goes out-of-step and backup protection.

Transmission faults unload the machine because the watt load is displaced by vars. The loss of load accelerates the machine and, at some point, as the power angle and speed differences increase, the unit becomes unstable and can no longer maintain synchronization with the electrical system, which significantly aggravates the disturbance and can cause a major electrical system upset. This is called the *critical clearing time* and is usually in the range of 6 to 20 cycles, depending on the type of fault and severity. Worst-case conditions can cause electrical system outages and the islanding of loads.

The second issue is backup protection; high voltage transmission lines almost always have backup schemes that are overreaching and do not rely on high-speed communication systems. Figure 4.9 shows a typical transmission line backup protection scheme that utilizes zone 1 and zone 2 directional distance or mho-type impedance relays. Usually zone 1 will trip without time delay and is set for 80% of the impedance ohms of the line. Depending on the length of area transmission lines, zone 2 will be set for 120% of the line impedance or greater, with a typical time delay of 0.4 seconds or 24 cycles for coordination purposes. This time delay usually exceeds the critical clearing time of generating units, and nearby on-line generation will likely lose synchronization with the system before line zone 2 relays can time out to clear faults beyond the lines. It is not unusual to find generating station high voltage switchyard bus differentials, unit differentials, transformer differentials, and feeder differentials that are not backed up and rely entirely on zone 2 clearing if the single protection schemes fail to interrupt bus, transformer, or

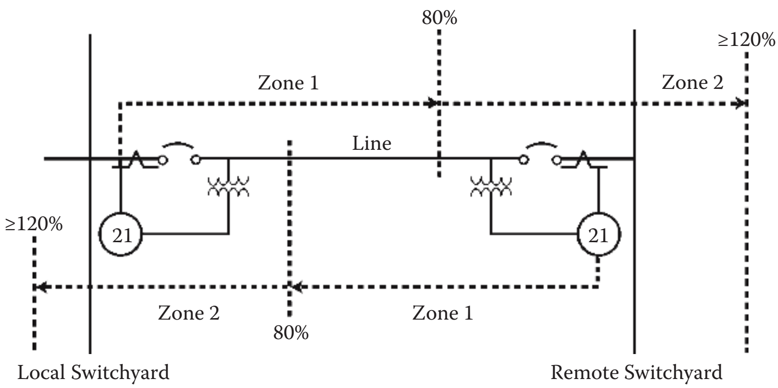


FIGURE 4.9
Transmission Line Backup Impedance Zones

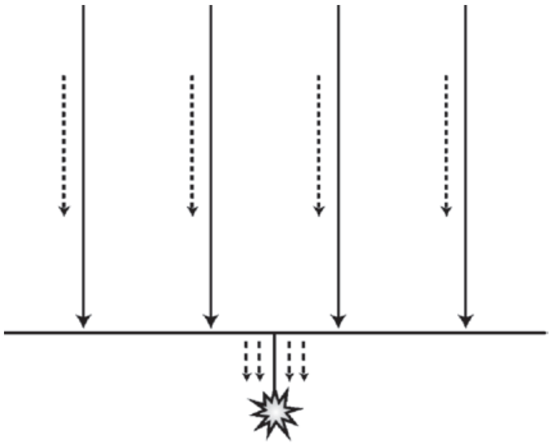


FIGURE 4.10
Fault Current Distribution and Infeed Ohms

feeder faults. Additionally, depending on the number of transmission lines in the switchyard, the zone 2 relays and directional ground overcurrent relays at the remote ends of the lines may not be able to detect the faults beyond the lines due to current distribution and infeed ohms.

Figure 4.10 represents the current distribution and infeed problem. In the case of directional ground overcurrent relays, the amount of ground current in each line is reduced because the fault current is shared by all lines. If nearby generation is also feeding the ground fault, the fault current flowing in each line would be reduced further. The concerns are that the ground protection at the remote ends of the lines may not have enough sensitivity to detect local ground faults beyond the lines, and if they do, the fault clearing timing may be too long to avoid generator instability.

The other issue is infeed ohms, which is more of a problem if different sources are involved because the voltage drops are not congruent with a single source, that is, generating units, ties to other utilities, and more remote substations. Figure 4.11 shows the calculations for infeed ohms with two sources, A and B, with A having a per-unit impedance of 0.5 ohms and an additional 0.5 ohms to the fault location or 1.0 per-unit ohms total if B is not connected. First, the total circuit per-unit impedance and current is determined, then, the current contribution from A only is proportioned, and finally, the per-unit impedance seen by A to the fault location is proportioned at 1.5 per-unit ohms or 150% higher when B is included.

The worst-case location for infeed at a generating station would normally be faults near the high voltage bushings of reserve auxiliary transformers (RATs) that are fed from the same high voltage switchyard. In this case, the zone 2 relays at the remote end of the transmission lines may not be able to detect the fault to back up the RAT transformer differential and/or feeder

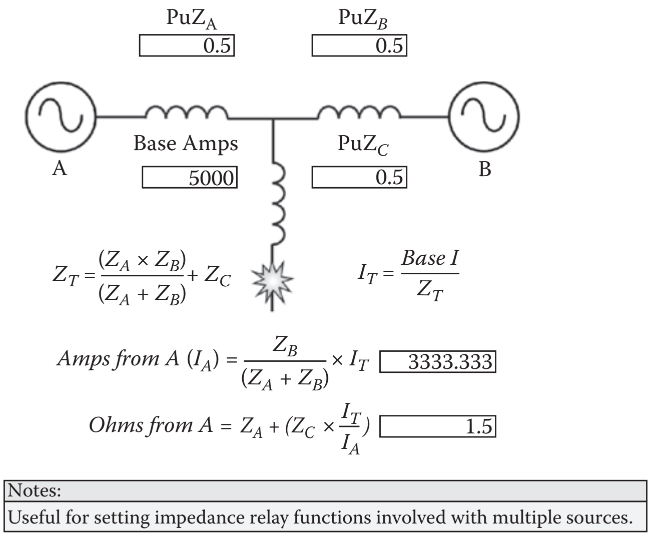


FIGURE 4.11
Infeed Ohms

differential protection. As mentioned before, line zone 2 time delays may be too long to avoid instability problems with the generating units. Additionally, generator protection functions that can see switchyard faults (negative phase sequence and backup impedance) may also have time delays that are too long to avoid instability or loss of synchronization with the electrical system. If the generating unit is equipped with out-of-step protection (many are not), the unit will be tripped off-line and isolated from the fault.

Usually, high voltage switchyards are equipped with breaker failure schemes that will clear everything necessary to isolate faults if a circuit breaker fails to interrupt the fault current in a timely manner. Normally, two conditions are required: a specified level of fault current and an energized breaker trip coil circuit. If these conditions are met, a timer output will operate to trip the necessary adjacent breakers or units to isolate the fault. It is not unusual to find breaker failure fault clearing times that are longer than the critical clearing time. The fault clearing time includes the initiating relay time, plus the breaker failure time delay, plus the longest breaker trip time, plus the longest breaker interrupting time. Consequently, close by generation may go out-of-step before the breaker failure scheme can isolate or clear the fault.

To counter some of the foregoing problems, it is recommended that zone 1 impedance relays be applied to backup high voltage unit, transformer, and feeder differential relays. The relays measure voltage and current at the generating station switchyard and look into the GSUTs or RATs; the zone 1 relay can be set with a small time delay (3 to 6 cycles) to ensure the differential schemes also operate. In regard to the GSUT, it should be ensured that the impedance relays cannot operate for loss-of-excitation events and cannot see unit auxiliary transformer (UAT) medium voltage faults for coordination. With the RAT transformer, the relay can be set to look halfway into the transformer to ensure it cannot overreach and see medium voltage faults. The advantage of applying impedance elements is they are not dependent on the strength of the electrical system, which varies depending on the number of sources available at the time of the fault. Ohms are ohms, and the impedance of a transmission line or transformer does not change when generating units or lines are placed into or out of operation. Early impedance relays were not directional and consisted of a circle that was symmetrical and encircled the point of origin. These impedance elements were supervised by directional contacts or relays. When directional electromechanical impedance relays were initially developed, the term *mho* was used, because the torque equations included the reciprocal of ohms. The elements normally encircle the first quadrant, which represents a series current lagging circuit.

4.4 Generator Protective Functions

This section will develop the protective function settings for the 578.6 MVA steam turbine generator and its associated step-up transformer and high voltage electrical system as previously shown in Figures 4.1, 4.2, and 4.3. Many of the electrical protection functions in a generator package are applied to protect the prime mover or turbine and not just the generator. The suggested settings are for 100 MVA and larger two and four pole cylindrical rotor generators connected to typical utility transmission or sub-transmission systems. Slower speed salient-pole generators and smaller units connected to weaker systems or units with different or unusual electrical configurations may present special circumstances that are not covered in this chapter. The following material is presented in numerical order according to the standard device numbers assigned for different relay functions.

4.4.1 Backup Impedance (21)

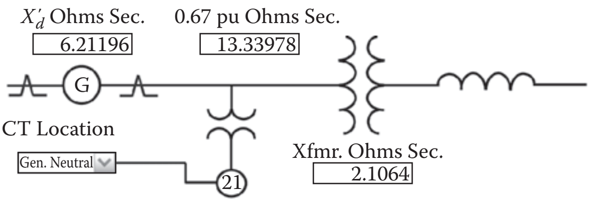
The 21 function is a backup impedance relay with one or two zones that look from the generator to the electrical system. The 51V time overcurrent element provides a similar function and it is preferable to apply the 21 backup impedance elements only. The 51V is a voltage controlled or restraint time overcurrent relay that permits setting the minimum trip threshold well below full load amps to allow for generator fault current decrements, but it will not operate unless the voltage is depressed by a fault condition.

No industry consensus exists on how to set the zone 2 impedance function; various papers propose different philosophies involving the shortest or longest line. Most of the papers advocate using the zone 2 function to trip or isolate the unit for close-in high voltage system faults that do not clear quickly enough. Fairly long time delays are necessary to ensure coordination with downstream electrical system protective devices, that is, breaker failure time delays, transformer bank overloads, zone 2 line protection time delays, and so forth. Because of the long time delay, this function may not be able to operate for close-in faults because the unit will likely lose synchronization with the system before the relay can time out. The out-of-step slip cycle can reset and pick up impedance elements as the impedance locus or swing travels through its cycle. Generators are thermally protected from high voltage phase-to-phase and phase-to-ground faults by negative phase sequence relays, but these relays will not respond to three-phase balanced events. Based on the foregoing, it is proposed that the zone 2 element be applied to thermally protect the generator from balanced three-phase prolonged system disturbances. For cross-compound units or generators operated in parallel, the settings will need to be modified to account for infeed impedance.

Figure 4.12 provides suggested settings for two element generator backup impedance relay schemes. Zone 1 is set to reach halfway into the GSUT (1.053 ohms) with a 0.1 second time delay. The short reach eliminates concerns about coordinating with downstream devices, and the short time delay is suggested to allow time for the differential relays to operate first. Operation of a primary relay provides important information about the location of the fault and verification that the relays are performing as designed. If the CTs are on the generator output side, it is customary to offset the mho circle by the direct axis saturated transient ohms to include the generator. If the CTs are on the neutral side, some manufacturers suggest using 0.1 ohms offset to provide some margin. As in revenue metering, the location of the potential transformers (PTs) determines the precise point of measurement because the circuit voltage drops are measured accurately. However, the CT location does have a directional impact on whether or not the event is in a forward (toward the electrical system) or a reverse direction (toward the generator). An angle of 75 degrees is often used to accommodate circuit and arc resistance.

The suggested reach for zone 2 is 150% of the rated generator MVA (.67 per unit) or 13.34 ohms with a time delay of 2.0 seconds to ensure downstream coordination. Because this is a three-phase setting, there is no concern about unbalanced events, and compensation to account for the impact of the delta-wye transformation on unbalanced faults is not required. The suggested offset and angle is the same as the zone 1 setting.

Generators are typically designed to carry 130% of rated stator amps for 60 seconds and 180% for 20 seconds. Accordingly, the foregoing setting of 150% or greater for 2.0 seconds has more than adequate thermal margins. As covered in Chapter 3, transformers can handle 150% for a little over 9 minutes. A 2.0 second time delay is suggested because it is the short circuit



Zone 1 Forward = 0.5 × Xfmr. Ohms Sec.	1.0532
Zone 1 Offset = 0.1 Ohms (neutral CT) / X'_d Ohms Sec. (output CT)	0.1
Zone 1 Angle	75
Zone 1 Time Delay Seconds	0.1
Zone 2 Forward = 0.67 per unit	13.339780
Zone 2 Offset = 0.1 Ohms (neutral CT) / X'_d Ohms Sec. (output CT)	0.1
Zone 2 Angle	75
Zone 2 Time Delay Seconds	2

Notes:
All ohms are generator base secondary.
Z1 Forward reaches halfway into transformer.
Z1 Time ensures differential targets.
Z2 Forward = 150% rated MVA = 0.67 pu.
Z2 Time ensures downstream coordination and thermal protection.
Z2 is a three-phase setting (Xfmr. comp. not necessary) and relies on (46) function to protect the machine from prolonged unbalanced faults.

FIGURE 4.12
Generator Backup Impedance Settings

electromechanical force withstand time for transformers and it should also coordinate with all downstream protective devices on a typical utility system.

It is doubtful that turbine/generators can provide 150% of rated megawatt load for 2.0 seconds, and utility load shedding programs should operate to bring the megawatt demand back into balance if the watt deficiency is severe enough. Governor droop settings for steam units are usually 5%. This is really control system terminology, but a simplistic way of looking at it is that it takes a 5% speed change to get the control valves fully opened or closed. During an earthquake islanding event in California, a digital fault recorder captured a 215 MW generator that was subjected to twice rated load, and the voltage collapsed to zero in 6 cycles. The general rule of thumb is that generating units should not try to pick up more than 10% of rated MW at any one time. The foregoing discussion on megawatts is really a mute point because the angle is set at 75 degrees (mostly vars) and the ohmic reach would be substantially lower (higher current) at reduced angles. Angles greater than 75 degrees would also need a slightly higher current to operate. For example,

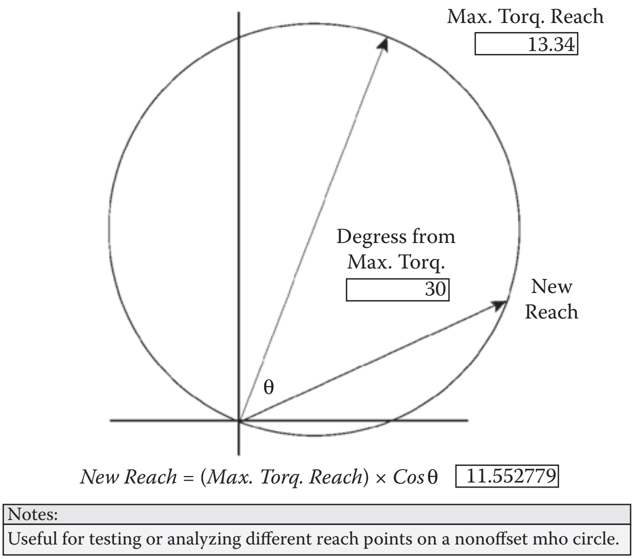


FIGURE 4.13
Mho Circle Reach Points

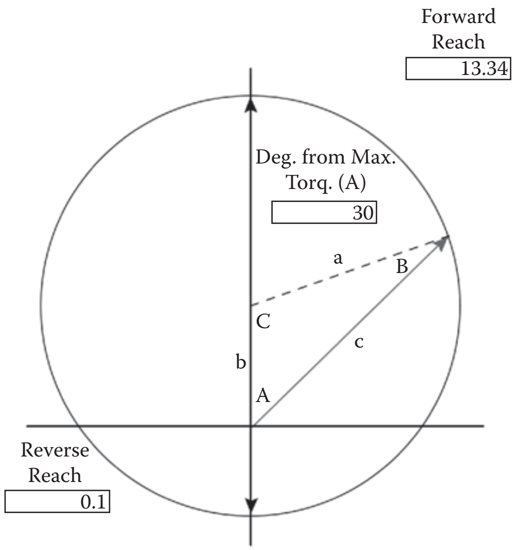
at 90 degrees, the reach point would be 12.89 ohms, or about 3.4% lower. However, generators can carry substantial vars that may thermally overload path components during major system disturbances. Since the normal utility system relies on capacitor banks and not generation to carry the system var requirements, excessive var loading for 2.0 seconds would be more indicative of a system fault that did not clear properly. Due to infeed concerns, it is not advised to increase the setting above the 150% MVA level or reduce the ohmic value further.

If the mho circle is not offset, the circle ohmic or impedance points can be calculated by simply taking the cosine of the angle deviation from the circle diameter or maximum reach point, as illustrated in Figure 4.13. The relay will actuate whenever the ohmic value is inside the circle.

Figure 4.14 shows an offset mho impedance circle for generator backup applications. Ohmic values on the circle can be calculated by using the trig method presented in the figure.

4.4.2 Volts/Hz (24)

This is a very important protection function for generators and connected transformers. The easiest way to catastrophically destroy a generator or its connected transformers is by overfluxing the iron laminations in their cores. The term *volts per hertz* (volts/Hz) is used because of the impact underfrequency operation has on the level of flux in the core. In the case of transformers, a reduced frequency will lower the exciting impedance, causing a



Radius (a) = (*Forward* + *Reverse*)/2 $\qquad b = a - Reverse$

$$B = \arcsin\left(\frac{Sin\ A \times b}{a}\right) \qquad C = 180 - (A + B)$$

$$New\ Reach\ (c) = \sqrt{a^2 + b^2 - (2\ ab\ Cos\ C)} \qquad \boxed{11.581361}$$

Notes:
Useful for testing and analyzing different reach points on offset mho circles.

FIGURE 4.14
Offset Mho Circle Reach Points

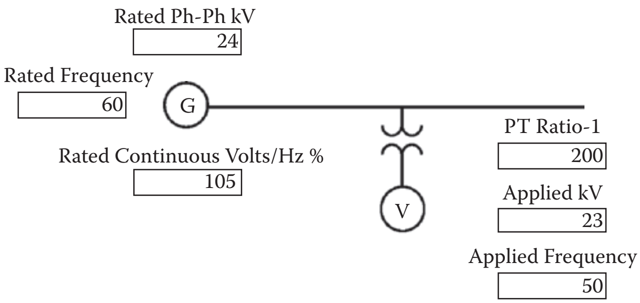
higher exciting current, more ampere-turns, and increased magnetic flux in the core iron. The increased magnetic flux will raise the level of eddy currents in the laminations, which results in higher core iron temperatures and saturation. As the laminated iron saturates, the magnetic flux will spill into structure areas that are not designed to carry flux, and those areas will also overheat from eddy currents. In the case of generators, the core iron flux is not a direct function of frequency or speed, and the no load DC field is safe over the entire speed range. However, a generator is like a tachometer: the slower the generator's speed, the lower the output voltage. If the automatic voltage regulator is in service, it will try to correct for the reduced output voltage by increasing the DC field current, which can overflux the core iron depending on the amount of voltage regulator correction. Consequently, the expression volts/Hz will work equally well for generators and transformers. Generators are normally designed to carry 105% of rated voltage continuously and transformers 110% at no load and 105% at full load, but credit can be taken for the internal voltage drop in transformers. Accordingly, the generator volts/Hz relays will normally provide protection for connected transformers, depending on the load currents, voltage drops, and rated winding voltages. The continuous rated frequency voltages of 105% or 110% are also the continuous volts/Hz ratings for the apparatus.

This protection is essential at generating stations because of the numerous ways that overexcitation can occur through operating mistakes or equipment failures. Although many generator voltage regulators are equipped with volts/Hz limiters and some are equipped with volts/Hz tripping logic, normal practice is to provide volts/Hz protection in a separate package over concern that there may be common modes of failure that can impact the voltage regulator control as well as its protective functions. The short time withstand capabilities of the apparatus for severe events does not allow time for operator interdiction before catastrophic damage can occur. During startup, in some designs, excitation is applied at very low speeds, which is no problem, as mentioned earlier, as long as the automatic voltage regulator is out of service and the no load field current is not exceeded by more than 5%. As a generator is loaded, its DC field is increased to compensate for internal voltage drops and the subtractive flux (armature reaction) from the higher current flow in the stator windings. Depending on design details, the no load field current is somewhere in the neighborhood of 50% of the full load field current. Typically, a generator can withstand a full load field with no load on the machine for only 12.0 seconds before damage occurs to the core iron. The typical withstand at 115% volts/Hz is around 5.0 minutes. The shape or slope of the withstand curves for generators and transformers are usually similar, with the main difference being the continuous rating starting points.

Figure 4.15 covers the procedure for calculating the impact of operating generators at abnormal voltages or frequencies. For reference, the maximum primary and secondary 60 cycle voltages are calculated. A base volts/Hz ratio is determined by dividing the rated kV by the rated frequency. An applied volts/Hz ratio is then determined by dividing the applied kV by the applied frequency. The actual or applied volts/Hz percentage can then by determined by dividing the applied ratio by the base ratio and multiplying by 100. In this example, the generator's continuous volts/Hz rating of 105% is significantly exceeded with a calculated percentage of 115% even though the applied voltage of 23 kV is well below the 60 Hz maximum rated voltage of 25.2 kV.

Figure 4.16 shows the procedure for calculating the impact of operating the GSUT at the same voltage and frequency values used in the prior example for the generator. In this case, although the maximum rated 60 cycle voltages for the generator and transformer are both around 25 kV, the underfrequency event is a little more severe for the transformer with a higher volts/Hz percentage of 121% compared to only 115% for the generator. This is because the base ratio for the transformer is lower due to the reduced kV rating of its primary winding.

Figures 4.17 and 4.18 illustrate the Westinghouse overexcitation withstand curves for generators and transformers respectively. Although these curves



$$Max.\ Rated\ kV = \frac{\%\ Rated\ Volts/Hz}{100} \times Rated\ kV \qquad \boxed{25.2}$$

$$Max.\ Rated\ Sec.\ Volts = \frac{Max\ Rated\ kV \times 10^3}{PT\ Ratio} \qquad \boxed{126}$$

$$Base\ Volts/Hz\ Ratio = \frac{Rated\ kV}{Rated\ Hz}$$

$$Applied\ Volts/Hz\ Ratio = \frac{Applied\ kV}{Applied\ Hz}$$

$$Applied\ Volts/Hz\ \% = \frac{Applied\ Ratio}{Base\ Ratio} \times 100 \qquad \boxed{115}$$

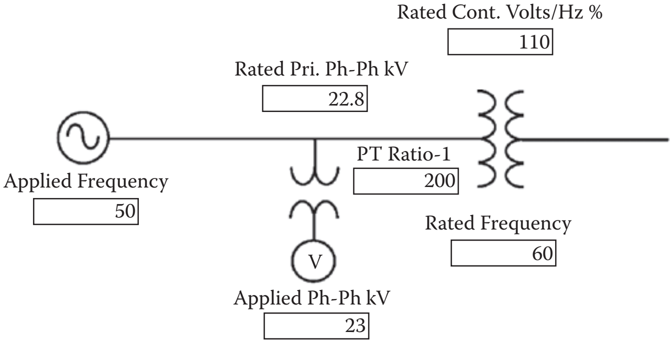
$$Applied\ Sec.\ Volts = \frac{Applied\ kV \times 10^3}{PT\ Ratio} \times 100 \qquad \boxed{115}$$

Notes:
Useful for assessing generator operation at abnormal voltages or frequency.

FIGURE 4.15
Generator Volts/Hz

tend to be a little more conservative than some manufacturers' curves, they are all in the same ballpark. Upon examining the generator curve, you will find that the generator can withstand the Figure 4.15 volts/Hz percentage of 115% for 5 minutes. The generator curve is flat at 125% and greater with a withstand time of only 0.2 minutes or 12 seconds. The connected transformer, however, is experiencing a volts/Hz percentage of 121% and the associated withstand time extrapolated from the transformer curve is about 4.5 minutes. Therefore, in this case, the transformer is a little more limited.

Figure 4.19 provides suggested settings for a three element volts/Hz protection scheme. The first element is set to alarm at 106% or 1 percentage point above the continuous rating. The second element is for a curve with a minimum pickup point of 106% and a time delay of 45 seconds at 110%, and the third element has a minimum pickup point of 118% and a fixed time delay of 2.0 seconds. This setting complies with General Electric (GE) recommendations and has more than ample thermal margin to ensure protection of their machines. Consequently, in this case, it will protect both the generator



$$\textit{Max. Rated kV} = \frac{\%\ \textit{Rated Volts/Hz}}{100} \times \textit{Rated } kV_{pri} \qquad \boxed{25.08}$$

$$\textit{Max. Rated Sec. Volts} = \frac{\textit{Max. Rated kV} \times 10^3}{\textit{PT Ratio}} \qquad \boxed{125.4}$$

$$\textit{Base Volts/Hz Ratio} = \frac{\textit{kV Rated}}{\textit{Hz Rated}} \qquad \textit{Applied Volts/Hz Ratio} = \frac{\textit{kV Applied}}{\textit{Hz Applied}}$$

$$\textit{Applied Volts/Hz \%} = \frac{\textit{Applied Ratio}}{\textit{Base Ratio}} \times 100 \qquad \boxed{121.052632}$$

$$\textit{Applied Sec. Volts} = \frac{\textit{kV Applied} \times 10^3}{\textit{PT Ratio}} \qquad \boxed{115}$$

Notes:
Useful for assessing transformer operation at abnormal voltages and frequency.

FIGURE 4.16
Transformer Volts/Hz

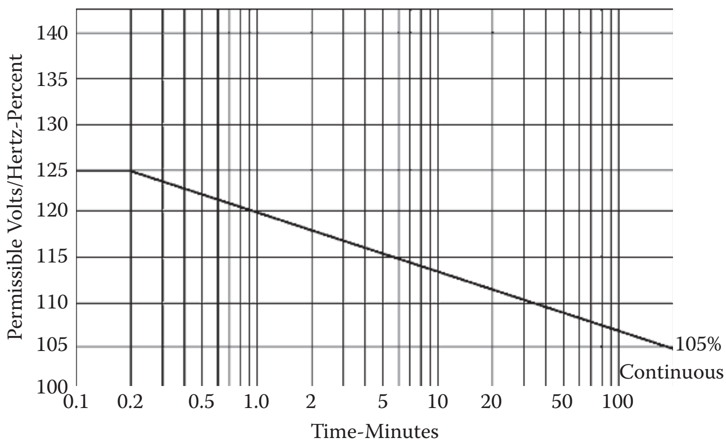


FIGURE 4.17
Westinghouse Generator Volts/Hz Withstand Curve (Used with permission of Siemens Energy, Inc.)

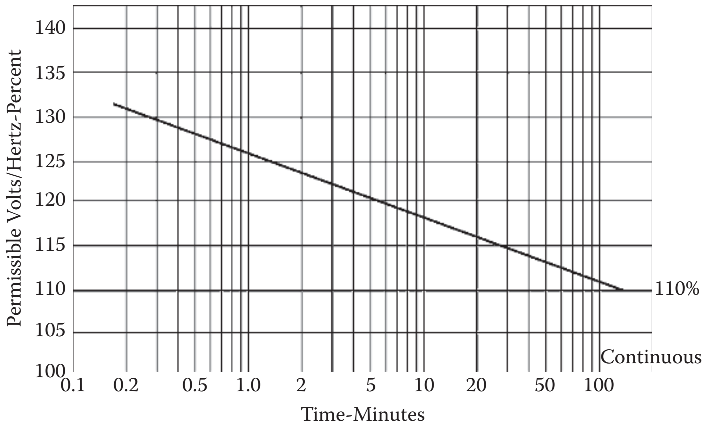
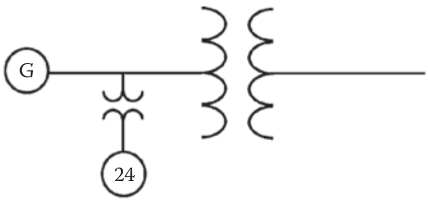


FIGURE 4.18
Westinghouse Transformer Volts/Hz Withstand Curve (Used with permission of Siemens Energy, Inc.)



Alarm Pickup %	106
Alarm Time Delay Seconds	1
Curve Pickup %	106
Curve Timing %	110
Curve Timing Seconds	45
Definite Pickup %	118
Definite Time Delay Seconds	2

Notes:
Complies with GE recommendations for their machines and should not cause nuisance tripping on a normal utility system. Since transformers usually have a greater withstand (110% instead of 105%), they will normally be protected by the generator settings.

FIGURE 4.19
Volts/Hz Settings

and connected transformer under study. Experience has shown that the proposed settings will not cause nuisance tripping on a normal utility system; the suggested settings were applied by a large generation company that had experienced major generator damage on two machines from overexcitation and did not want to push the thermal margins. Although overfluxing the

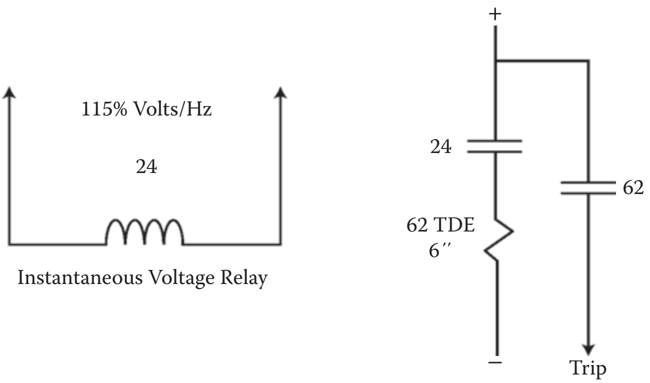


FIGURE 4.20
Simple Single Element Volts/Hz Tripping Scheme

iron core is considered, a thermal event with time delays before damage, a large generator manufacturer did experience an almost instantaneous failure in their test pit. The iron is stacked on key-bars and an overfluxing event caused enough of a potential difference between bars to push high damaging current through the back iron area.

Figure 4.20 covers a simple yet effective single element volts/Hz tripping scheme that utilizes an instantaneous plunger-type electromechanical voltage relay. The relay coil will mimic a volts/Hz function since the ampere turns increase as the frequency is reduced from lower impedance, which results in a lower actuation or trip point. Because only one element is provided, the suggested setting is 6.0 seconds at 115%. The withstand times below 115% are greater than 5 minutes and operator interdiction should be able to protect the machine. Since 6.0 seconds is well under the 12-second withstand time for severe events the setting provides more than adequate protection margins for events 115% and higher.

Good practice is to have the automatic voltage regulator (AVR) fed from a different set of potential transformers than the volts/Hz protection. The volts/Hz relays cannot operate if they do not receive potentials due to blown fuses or an operating failure to rack-in the potential transformers or install the fuses. Depending on design details, if the AVR is on the same potential transformers as the volts/Hz relays, partial or full loss of potentials can cause the AVR to go into a full boost mode and the volts/Hz protection may not be able to operate depending on which phases are impacted by the loss of voltage and where the relays are connected. Volts/Hz is more of a problem during startup because of the underfrequency operations prior to synchronizing. Depending on the design details of the particular excitation system, volts/Hz excursions well over 140% are possible. If the excursions are high enough, auxiliary transformers are likely to saturate and trip on differential protection. There have also been cases where generating units have been tripped off-line while connected to the electrical system as a result of overexcitation levels that have exceeded 115%.

4.4.3 Sync Check (25)

Another relatively easy way to damage a turbine/generator is to synchronize or parallel out of phase with the electrical system. Out-of-phase synchronizing operations can damage or reduce the remaining life of turbine/generator rotors and stationary components. Angular differences as little as 12 degrees can instantly apply 1.5 per unit or 150% of full load torque on the turbine/generator shaft system. The 1.5 per-unit value was measured by a shaft torsional monitoring data acquisition system (EPRI project) at a large coal plant that was paralled to the 500 kV bulk power electrical system with a 12-degree angular difference during synchronization. Plant operations acknowledged that the turbine deck really shook. Although turbines are generally built to withstand angular differences above 10 degrees, most manufacturers recommend limiting out-of-phase synchronizing operations to no more than 10 degrees maximum. Generator sync-check relays should supervise both manual and automatic modes of operation to prevent turbine/generator damage from operator errors or from malfunctioning automatic synchronizing relays. For this reason, it is normal practice to have the sync-check relay function provided in a different package than the automatic synchronizing relay to avoid failure modes that can impact both functions.

A clockwise rotation of the synchroscope in the majority of designs indicates that the turbine/generator has a higher speed or frequency than the electrical system. This condition is desirable to reduce the possibility that the unit will be in a motoring mode of operation and trip on reverse power protection when the breaker is closed. The voltages should be matched during synchronizing with a slightly higher generator voltage to ensure var flow into the system instead of the generator.

Figure 4.21 provides suggested settings for generator sync-check relays. The proposed default angles are 5 degrees advance and 5 degrees late. The calculations consider circuit breaker closing times and maximum allowable slip rates and determine the minimum seconds per scope revolution and the worst-case angle. The minimum seconds per scope revolutions is provided as a guide for operations or for setting auto synchronizing relays; the scope revolutions cannot go faster and be within the operating range of the sync-check relay. The worst-case angle assumes the breaker close signal is dispatched at the maximum late angle and that the breaker XY control scheme seals in. It then looks at the maximum allowable slip frequency (proposed setting of .05 Hz) and calculates the worst-case out-of-phase angle when the breaker contacts actually close. In this case, the worst-case angle of 8.6 degrees complies with manufacturer's recommendations not to parallel if the angle exceeds 10 degrees. Experience has shown that the pro-

Advance Angle: 5

Late Angle: 5

CB Closing Seconds (T): 0.2

Allowable Maximum Slip Frequency (F)	0.05
Minimum Seconds/Scope Revolution (R) = 1/F	20
Degrees/Second (D) = 360/R	
Worst Case Angle = DT + Largest Angle Setting	8.6

Notes:
Many manufactures recommend limiting out-of-phase conditions to 10 degrees. A plus and minus 5-degree setting should provide enough margin for operations depending on the response of the particular governor control system.

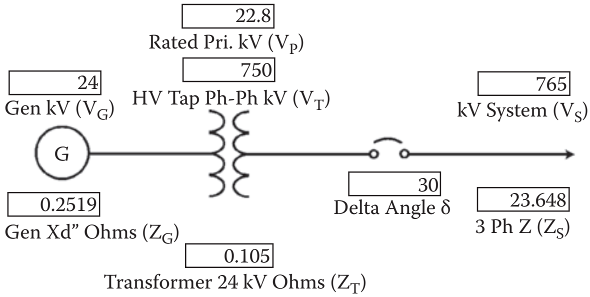
FIGURE 4.21
Synchronizing Check Relay Settings

posed settings are practical and within the operating capability of most turbine-governor control systems.

Other available settings in the newer digital relays might include ratio correction factors for GSUT taps because generator potentials are normally compared to switchyard high voltage potentials and allowable percent voltage mismatches. Although this writer is less concerned about var flows from voltage differences because they do not represent real power and the shaft torques are minimal, plant operators should limit voltage mismatches to less than 5%.

Some of the newer digital sync-check relay functions also include slow breaker protection. Once the breaker control signal is dispatched, it seals in, and there is no way to abort the close operation because there is a 52a contact in series with the trip coil that prevents the coil from being energized until the breaker is actually closed. The slow breaker function could be set to operate breaker failure relaying to clear the adjacent breakers if the angular differences reach 10 degrees or more, indicating that the breaker is slow to close for mechanical reasons.

The maximum amount of symmetrical AC current that flows during synchronizing at rated frequency can be approximated by the expression in Figure 4.22. Generator side voltage and ohms from Figures 4.1 and 4.2 were used in the calculation and reflected to the 765 kV side. The system three-phase 765 kV short circuit ohms were transferred from Figure 4.3.



$E_G = V_G \times R \times 10^3$ $\quad$ *Transformer Ratio* $(R) = \dfrac{V_T}{V_P}$

$E_S = V_S \times 10^3$

Reflected Primary Ohms $(Z_R) = (Z_G + Z_T) \times R^2$

System Amps $(I_{AC}) = \dfrac{\sqrt{E_S^2 + E_G^2 - (2E_S \times E_G \times Cos\ \delta)}}{Z_R + Z_S}$ $\boxed{983.371}$

Generator Amps $= I_{AC} \times R$ $\boxed{32347.725}$

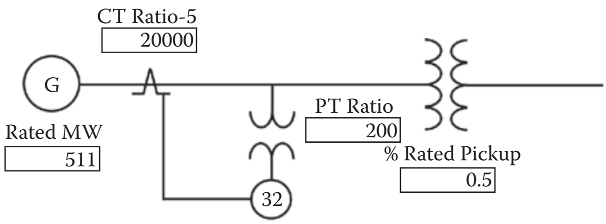
Notes:
The reactance values are in actual ohms and not per-unit values.

FIGURE 4.22
Maximum Symmetrical Synchronizing Current

Figure 4.22 shows that the 765 kV current would be approximately 983 amps and the generator amps would be approximately 32,348 at 30 degrees. At 60, 90, and 180 degrees, the approximated 765 kV currents for the parameters presented in the figure would be 1897, 2682, and 3793 amps, respectively. The generator side current at 180 degrees out would be around 124,767 amps. This does not include the DC component or peak asymmetrical current, which will also be present. Obviously, the generator and transformer windings need to be able to handle the peak electromechanical forces. The event is transitory in nature as the asymmetrical current decays and the generator pulls into step with the system and the power angle becomes congruent with the prime mover. The air gap torque is difficult to calculate and depends on electromechanical forces, circuit resistance, and the amount of power transfer from angular differences. Possible damage assessment is particularly complicated and associated with the peak torques and the natural frequencies of the shaft and other mechanical components as the event decays. The associated apparatus may have reduced life from other events or excursions, startup/shutdown cycles, or design or repair oversights, and major equipment damage may occur if the incident is severe enough.

4.4.4 Reverse Power (32)

Reverse power protection for steam turbine generators is normally applied to protect turbine blades from overheating. The longer low-pressure blades



$$\textit{Per-Unit Pickup } (P) = \frac{\%\ \textit{Rated}}{100} \qquad \boxed{0.005}$$

$$\textit{MW Pickup } (M) = P \times \textit{Rated} \qquad \boxed{2.555}$$

$$\textit{Secondary Watts Pickup} = \frac{M \times 10^6}{(CT/5) \times PT} \qquad \boxed{3.193750}$$

$$\textit{Time Delay Seconds} \qquad \boxed{20}$$

Notes:
Steam turbines will generally consume around 3% of rated MW in a motoring condition and can normally withstand the operation for several minutes before substantial overheating of LP turbine blades.

FIGURE 4.23
Reverse Power Relay Settings

can overheat from windage in the absence of steam flow. Withstand times for steam turbines in a motoring mode of operation are usually in neighborhood of 10 minutes. Motoring is not harmful to generators as long as the proper level of excitation or DC field current is maintained. Steam turbines generally consume around 3% of their rated MW when motoring. This function is sometimes used on combustion turbines for flameout protection and to limit watt consumption from the electrical system, as motoring power is usually much greater for combustion turbines. With hydro turbines, there is concern about blade cavitations during conditions of low water flow.

Some designs have reverse power supervision of unit breakers to mitigate the possibility of overspeed conditions, and others use reverse power permissives in their automatic shutdown circuitry to delay opening unit breakers until the unit is in a motoring condition. Figure 4.23 calculates the setting for a reverse power relay that is applied to protect steam turbine LP blades from overheating. Because the actuation point needs to be well below the unit motoring requirement, a minimum pickup point of 0.5% of turbine rated MW (3.19 watts secondary) with a time delay of 20 seconds is suggested. The suggested time delay is provided to reduce the possibility of nuisance tripping during synchronizing operations. Since the withstand times are so long, an argument can be made for even more time delay, but many in the industry will opt for a shorter time delay of 10 seconds or less. In the case of combustion turbines, the time delay may need to be reduced if the relay also provides flameout protection. The suggested settings should be compared to the turbine/generator manufacturer's motoring data to ensure that adequate margins are provided.

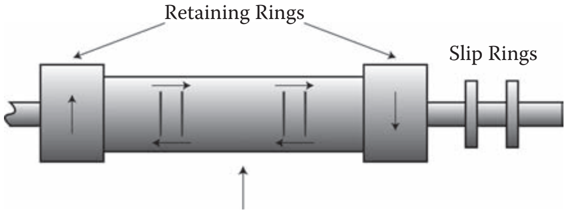


FIGURE 4.24
Cylindrical Generator Two-Pole Rotor Slip Frequency Currents

4.4.5 Loss of Field (40)

Loss of field relays are applied primarily to protect synchronous generators from slip frequency AC currents that can circulate in the rotor during underexcited operation. Underexcitation events are not all that uncommon; consequently, this is a relatively important function. Generators can lose field or operate underexcited from a variety or reasons, for example, voltage regulator or power electronic failures, loss of excitation power supplies, opening of the laminated main leads under the retaining rings, opening of the DC field circuit breaker, arcing at the slip rings, differences between system and generator voltages when the voltage regulator is on manual, and so forth.

Figure 4.24 illustrates a cylindrical two-pole generator rotor and the associated slip frequency currents during loss of excitation. Because a two-pole machine rotates at 3600 RPM, the centrifugal force is very high. The figure shows a pole face (opposite polarity on the other side); the field turn slots cannot be seen in this view and would be located at the top and bottom areas. The copper field turns are contained in the forging slots by aluminum or steel wedges that are in a dovetail fit. The circumferential slots in the pole face area are provided to equalize rotor flexing. The retaining rings at each end contain the copper end turns, which are under stress from the rotational forces.

Synchronous generators are not designed to operate as induction machines and are not very good at it. Steady state instability happens when the generator slips poles, which occurs when the power angle exceeds 90 degrees, as shown by the dashed line in Figure 4.25. This occurs because the magnetic coupling between the rotor and stator is weakened by the event and eventually becomes too weak to maintain the output power, and synchronization with the electrical system is lost when the machine speeds up. The speed differences cause induced slip frequency currents (0.1% to 5% depending on initial load) to flow in the rotor body. The circulating currents can be damaging to the highly stressed retaining rings, circumferential slots, forging, and wedges. Although thermal damage from the slip frequency currents is the primary concern, they also cause pulsating torques that can impact the life of mechanical components.

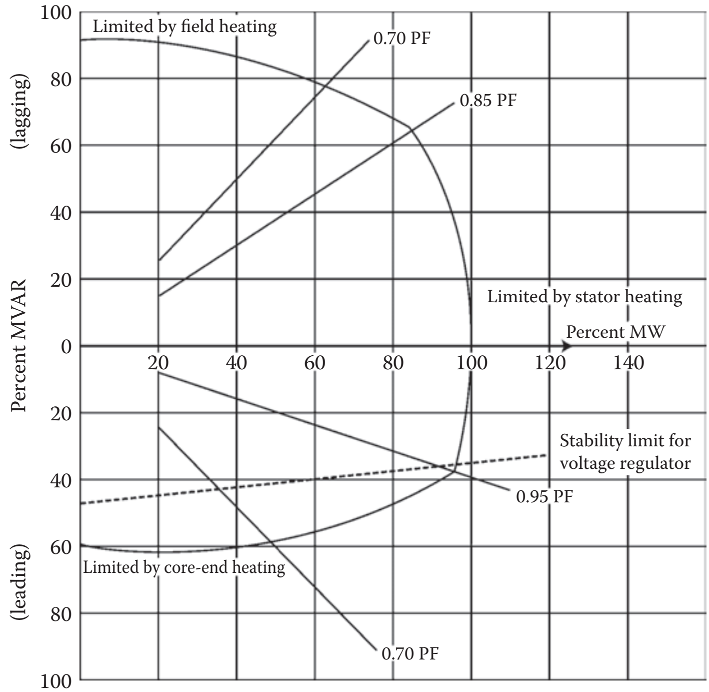
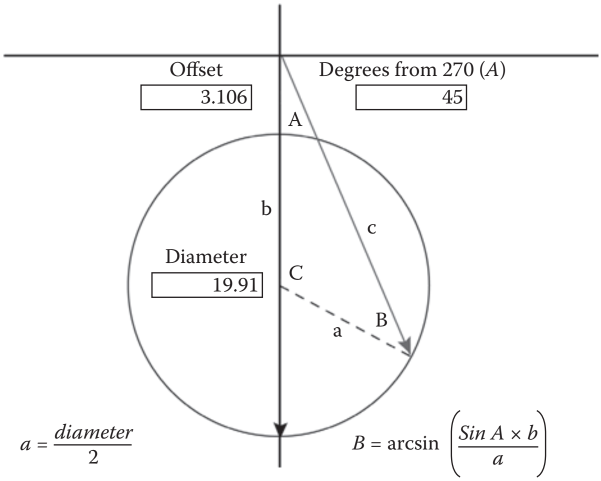


FIGURE 4.25
Generator Capability Curve

The output power on average is about 25% at full load; the var increases typically create stator currents in the range of 114% to 213% that can cause thermal damage to the stator windings after 20 or more seconds.

In addition to instability, the generator capability curve in Figure 4.25 shows the operating limitation of a typical generator at rated hydrogen pressure. The lagging area represents overexcitation, or boost vars, and the primary limitation is field winding overheating from the increase in field current I^2R losses. The leading area represents underexcitation, or buck vars, and is limited primarily from flux impingement of the core iron end packets. The stator core iron is divided into laminations in the direction of the rotor magnetic flux linkage to reduce eddy current losses. However, the rotor end turns beneath the retaining rings change the direction of the rotor flux, and it links with the stator core end iron at right angles, creating higher eddy current losses. The leading var flow in the stator winding also produces a flux that adds to the rotor end turn flux, aggravating the problem. Many large generators are equipped with flux shields at the core ends under the end windings and have increased bore diameters near the retaining rings to protect this area during operation.



$a = \dfrac{diameter}{2}$ $\qquad$ $B = \arcsin\left(\dfrac{\sin A \times b}{a}\right)$

$b = offset + a$ $\qquad$ $C = 180 - (A + B)$

$New\ Reach\ (c) = \sqrt{a^2 + b^2 - (2\,ab\,\cos C)}$ $\qquad$ 12.951321

Notes:
Useful for analyzing or testing various reach points on a loss of field or positive offset mho circle.

FIGURE 4.26
Loss of Field Mho Circle

Loss of field relays will operate for impedance swings that are inside their mho circles. Normal practice is to positively offset the mho circle by one-half the generator transient reactance ohms, as shown in Figure 4.26, to avoid stable swings that may get into this area during system disturbances and faults. Underexcitation will cause the generator to absorb lagging vars from the system (quadrant 4) that appear to be leading if the reference direction is watt flow from the generator to the system. Under normal operating conditions, generators supply watts and lagging vars to their associated step-up transformers and operate in the first quadrant. The figure also shows the trig calculation procedure for determining the ohmic value of different reach points on the mho circle.

Figure 4.27 illustrates an impedance swing caused by a loss of field event at full load. It starts out in the first quadrant in the load range and then swings into the impedance circle. It can take seconds (2 to 8 seconds) to enter the mho circle, where it will continue to move and eventually exit the circle (1 to 10 seconds later) depending on the associated parameters, and then repeat the slip cycle. The load on the unit at the time of the loss of field event impacts the impedance locus of the event. The higher the load, the faster the impedance swing. Several other factors also impact the impedance locus, including strength of the electrical system, turbine/generator inertia constants, and type of event (shorted or open field circuit).

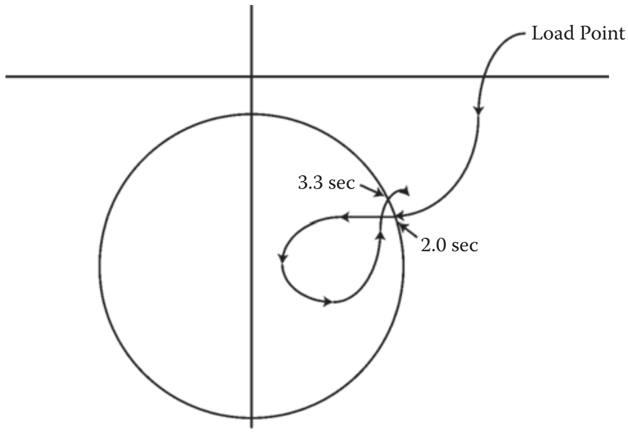
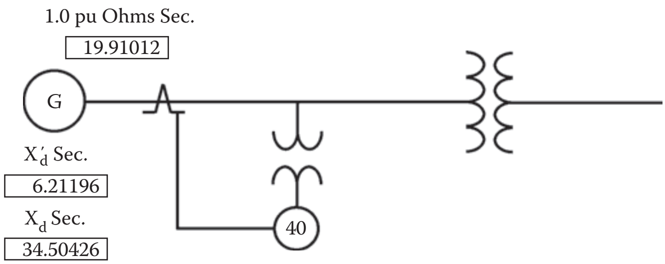


FIGURE 4.27
Loss of Field Impedance Swing



Zone 1 *Diameter* = 1.0 *pu Sec.*	19.91012
Zone 1 *Offset* = 0.5 X'_d *Sec.*	3.106
Zone 1 *Time Delay Seconds*	0.17
Zone 2 *Diameter* = X_d *Sec.*	34.50426
Zone 2 *Offset* = 0.5 X'_d *Sec.*	3.106
Zone 2 *Time Delay Seconds* = 2 × (*Zone* 1 *Seconds*)	0.34

Notes:
The mho circle settings are relatively standard across the industry. The time delays used in the industry vary depending on the particular source paper. The suggested time delays are conservative in the interest of ensuring protection of the generator.

FIGURE 4.28
Loss of Field Relay Settings

Figure 4.28 provides the suggested settings for a two-zone loss of excitation scheme. Both zones are offset by the same amount (3.1 ohms or one half the generator transient reactance). The suggested diameter for the zone 1 circle is 1.0 per unit or 19.9 ohms with a time delay of 0.17 seconds. The suggested diameter for the zone 2 circle is the generator synchronous reactance or 34.5 ohms with twice the time delay or .34 seconds. The suggested offset and mho circle diameters are quite standard across the industry. If only one zone of protection is applied, the zone 2 reach with the zone 1 time delay is recommended. However, the recommended time delays for two zones of protection differ, depending on the particular source paper, from as little as no time delays for zone 1 to as much as 1.0 second or longer for zone 2. For many years standard practice was to apply an electromechanical loss of field mho impedance relay with only one zone of protection that was set according to zone 2 in Figure 4.28, but with a built-in time delay of around 0.17 seconds. This setting did an excellent job of preventing rotor damage and did not cause nuisance tripping. Because the zone 2 mho circle represents a less severe event, doubling the time delay seems reasonable. If the time delay is too long, the impedance swing could exit the mho circle before the function can time out.

4.4.6 Negative Phase Sequence (46)

Negative phase sequence protection is applied to protect generators from reverse rotation double frequency currents that are induced into the rotor if the stator currents are not balanced (Figure 4.29). Significant unbalances can result from a circuit breaker pole that does not make, or a phase conductor that is open prior to, energization. It also provides thermal protection for system phase-to-phase and phase-to-ground faults that do not clear properly. System ground faults look like phase-to-phase faults to generators that feed delta-wye step-up transformers. However, because the negative phase sequence tripping time delays are quite long, the unit may lose synchronization and go out of step before the negative phase sequence relay can operate. As with loss of field, these currents can cause thermal damage to the retaining rings, wedges, and other rotor components and are potentially more damaging than loss of field induced slip frequency currents because the much higher frequency of 120 Hz causes the current to concentrate more on the outside surfaces (skin effect). The reverse rotation induced rotor currents also produces a slight negative torque resulting in torsional oscillations.

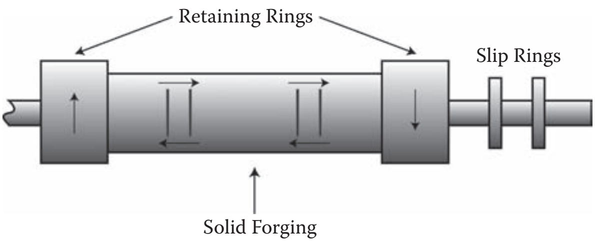


FIGURE 4.29
Negative Phase Sequence 120 Hz Reverse Rotation Induced Currents

Per ANSI/IEEE standard C50.13, generators are rated for both continuous and short time thermal capabilities for carrying negative phase sequence currents. The ratings vary depending on the size of the generator and whether or not it is directly or indirectly cooled. Directly cooled generators have gas or water passages that cool the stator conductors and special gas passages or zones that cool the rotor windings. Cylindrical rotor and salient pole generators equipped with amortisseur windings rated 960 MVA and smaller will have a continuous rating of at least 8% per standards. Salient pole generators with amortisseur and indirectly cooled cylindrical rotor machines will have a continuous rating of 10%. All generators rated 800 MVA and smaller will have a short time 1.0 per unit I^2T negative phase sequence thermal rating or "K" of at least 10. Indirectly cooled cylindrical rotor machines will have a K of 20 and salient pole generators a K of 40. In general, smaller and indirectly cooled machines will have a greater thermal capacity for negative phase sequence because the direct cooled machines have a relatively larger capacity or MVA and the cooling system is not as effective for the rotor. Generators larger than 800 MVA will have a reduced thermal capability to carry negative phase sequence rotor currents. Although tripping from this function is rare on large utility systems, negative phase sequence protection is almost always provided due to the thermal limitations of generator rotors.

Figure 4.30 shows full load amps (13,919) on A and B phases and zero current on C phase. This is really an A-B current; consequently, the A-phase angle is shown at 0 degrees and the B-phase angle at 180 degrees. To resolve

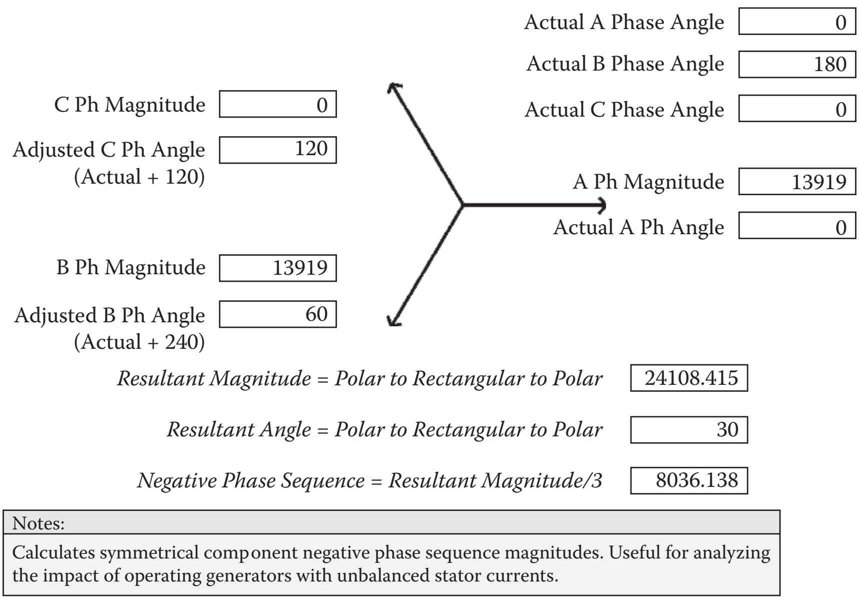


FIGURE 4.30
Negative Phase Sequence Magnitude

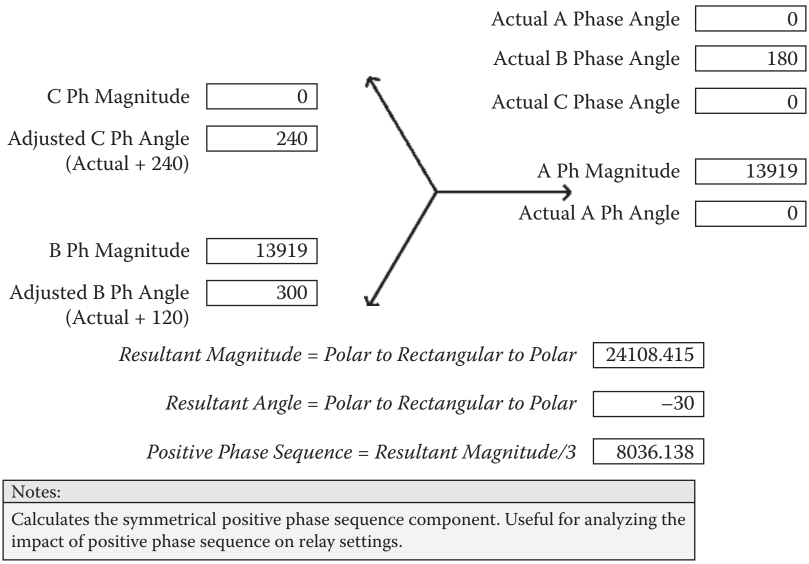


FIGURE 4.31
Positive Phase Sequence Magnitude

the symmetrical component negative phase sequence I_2 current magnitude, the angle for B phase needs to be advanced by 240 degrees and the angle for C phase by 120 degrees. After the angular advancements on B phase and C phase, the negative phase sequence magnitude of 8036 can be determined by dividing the vector sum by 3.

As a matter of interest, Figure 4.31 covers a similar process for determining the positive phase sequence magnitudes. For positive phase sequence, the B-phase angle is advanced by 120 degrees and the C-phase angle by 240 degree. As shown, for phase-to-phase events, the positive and negative components are equal to each other.

Also as a matter of interest, Figure 4.32 shows the calculation for the symmetrical zero phase sequence component. The zero phase sequence magnitude is simply the vector sum of actual angles (no angular advancement) divided by 3. In this case, the vector sum is zero, as A and B phases are displaced by 180 degrees. Accordingly, a phase to phase event does not contain a zero phase sequence component.

The generator withstand is based on the symmetrical component method of calculating negative phase sequence current. Figure 4.33 calculates the generator withstand time before rotor damage can occur and discloses that the 578.6 MVA generator can withstand 8036 amps or 57.7% of negative phase sequence I_2 stator current for 30 seconds before loss of life or rotor damage starts to occur.

The proposed negative phase sequence settings for the 578.6 MVA generator are presented in Figure 4.34. The suggested alarm and trip pickup

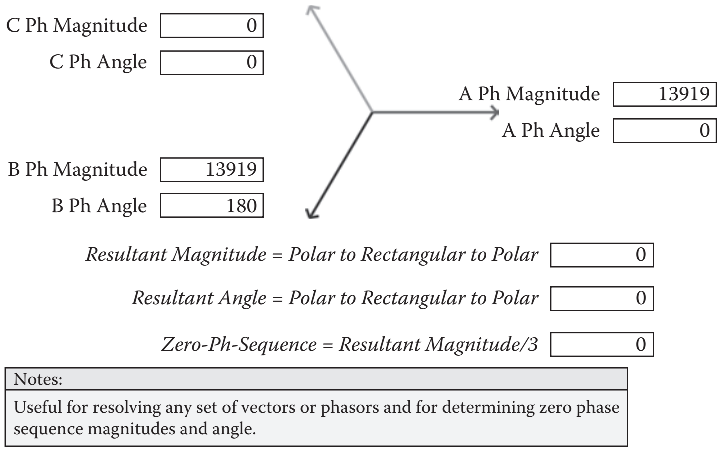


FIGURE 4.32
Zero Phase Sequence Magnitude

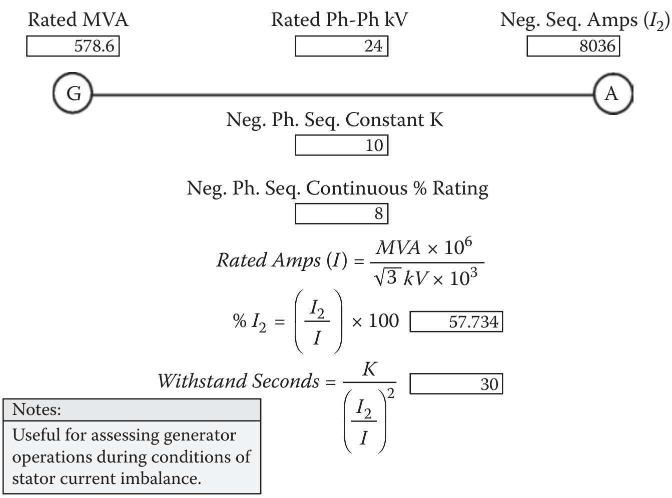


FIGURE 4.33
Negative Phase Sequence Withstand

points are 6% alarm and 8% trip. The suggested relay timing is for an I^2T or K value of 9 (90% of the rotor thermal rating is used up). These settings should not cause nuisance tripping or coordination problems on a normal utility system.

4.4.7 Inadvertent Energization (50/27)

Inadvertent energization of at-rest generating units is not all that uncommon. This can occur if unit switchyard disconnects that isolate units from

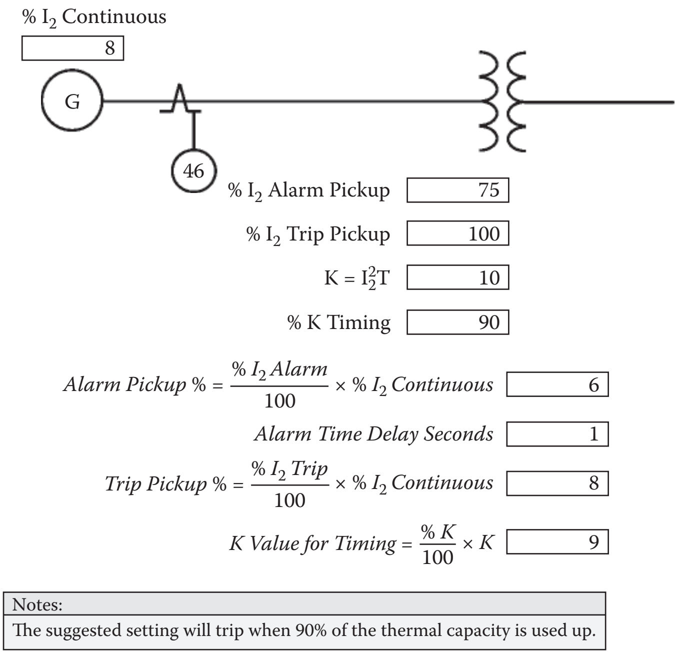
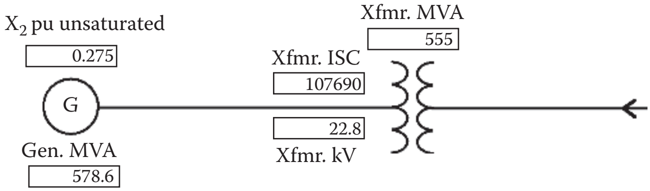


FIGURE 4.34
Negative Phase Sequence Relay Settings

energized ring buses or breaker and half configurations are inadvertently closed or if the unit breakers are closed when the isolating disconnects are closed. Some utilities install mid-position limit switches that will trip the associated high voltage breakers open when the disconnect swing hits the mid-position. Although a properly designed sync-check relay scheme should prevent inadvertent closures of generator breakers or unit switchyard breakers, one way or another, it seems to happen in the industry. If the inadvertent energization is long enough in duration, catastrophic generator damage can occur. Inadvertent energization can also occur through the UAT, but the current is much lower because of the relatively high auxiliary transformer impedance, and the auxiliary transformer overcurrent relays should be able to mitigate damage to the unit. During major outages, there is also concern that protective functions that might limit the duration may be out of service for relay testing purposes, or the potential transformers could be racked out or otherwise disabled.

Basically, the unit is being started across the line as a motor. Generators are not designed for this purpose, and severe overheating of stator and rotor components can occur. Additionally, the rotor wedges and amortisseur interfaces (where applicable) will not be held securely by centrifugal force, as they are during normal operation, and the loose fits can cause additional damage from arcing.



Gen. kV

24

$$Base\ I = \frac{Xfmr\ MVA \times 10^6}{\sqrt{3}\ Xfmr\ kV \times 10^3}$$

$$Z_T = \frac{Xfmr\ kV \times 10^3}{\sqrt{3}\ ISC}$$

$$Xfmr\ ISC\ per\ Unit\ Z = \frac{Xfmr\ MVA}{Xfmr\ kV^2} \times Z_T$$

$$Corrected\ Gen.\ per\ Unit\ (X_{2C}) = \frac{Xfmr.\ MVA}{Gen.\ MVA} \times \frac{Gen.\ kV^2}{Xfmr\ kV^2} \times X_2$$

$$Gen.\ Inadvertent\ Amps = \frac{Base\ I}{X_{2C} + Xfmr\ pu\ Z} \quad \boxed{33241.364}$$

Notes:
Approximates the initial current for the 3-phase inadvertent energization of a standstill generator.

FIGURE 4.35
Inadvertent Energization Current

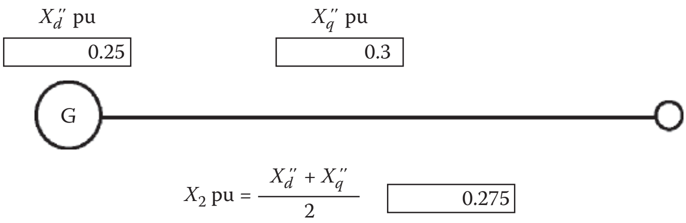
Figure 4.35 approximates the expected symmetrical current from energizing an at-rest machine. The base current is derived from the transformer MVA. The three-phase short circuit current on the 22.8 kV side of the GSUT is converted to ohms and then to per-unit ohms. The corrected generator unsaturated negative phase sequence per-unit impedance X2c can then be added to the transformer 22.8 kV short circuit per-unit impedance and divided into the base current to determine the at-rest energization current. In this example, the initial inrush current will be around 33,241 amps or 239% of full load amps. In-service loss of field, reverse power or anti-motoring, and generator and switchyard backup impedance relays may be able to see the event depending on their specific settings.

If the generator negative phase sequence reactance is not available, the per-unit value can be approximated by summing the direct and quadrature per-unit subtransient reactances and dividing by 2 as shown in Figure 4.36.

Newer microprocessor-based relays generally have logic functions that detect and trip for inadvertent energization conditions. This logic usually involves recognizing that the unit is off-line by the absence of voltage for a specified period of time and then measuring a sudden inrush of current.

4.4.8 Breaker Failure (50BF)

For designs that apply a breaker at the generator bus, some of the newer digital relays provide logic elements that can be mapped to provide breaker



Notes:
Approximates generator negative sequence per-unit impedance per IEEE tutorial 95 TP 102 "Protection of Synchronous Generators."

FIGURE 4.36
Negative Phase Sequence Reactance

failure protection for events that are normally isolated by opening the generator breaker. As with high voltage switchyard breakers, three logic elements are necessary, a specified level of current, an energized breaker trip coil circuit, and a time delay that is longer than the breaker trip time with margin. Tripping would include the unit, associated high voltage breakers, and low voltage auxiliary transformer breakers.

4.4.9 Pole Flashover (50NF)

Although high voltage unit breaker pole flashover is more likely during synchronizing operations where double voltage can exist as the synchroscope rotates, pole flashover can occur anytime the circuit breaker dielectric degrades from moisture intrusion, contamination, or a reduction in dielectric gas pressure. However, energizing an at-rest generator from a pole flashover would have the likelihood of being more damaging than a more transitory event where the generator is at or near synchronous speed. An at-rest machine will not rotate with a single-phase energization, and centrifugal force is not holding the rotor components securely, increasing the possibility of arc damage. Figure 4.37 illustrates the current flow paths on both sides of the GSUT for a C-phase pole flashover event and covers an approximation procedure for determining the high and low side currents into an at-rest generator. First, the generator per-unit negative phase sequence unsaturated reactance (corrected to transformer MVA and low side voltage), the transformer %Z (for the wye winding or 765 kV side), and the high voltage system ground fault current are converted to ohmic values. Then double the corrected generator negative sequence ohms (accounts for current flow into both A- and C-phase windings) are reflected to the system side of the GSUT. The total circuit high voltage side ohms would be the summation of the secondary side reflected ohms plus the transformer high side ohms plus the neutral reactor ohms plus the system ground fault ohms. The

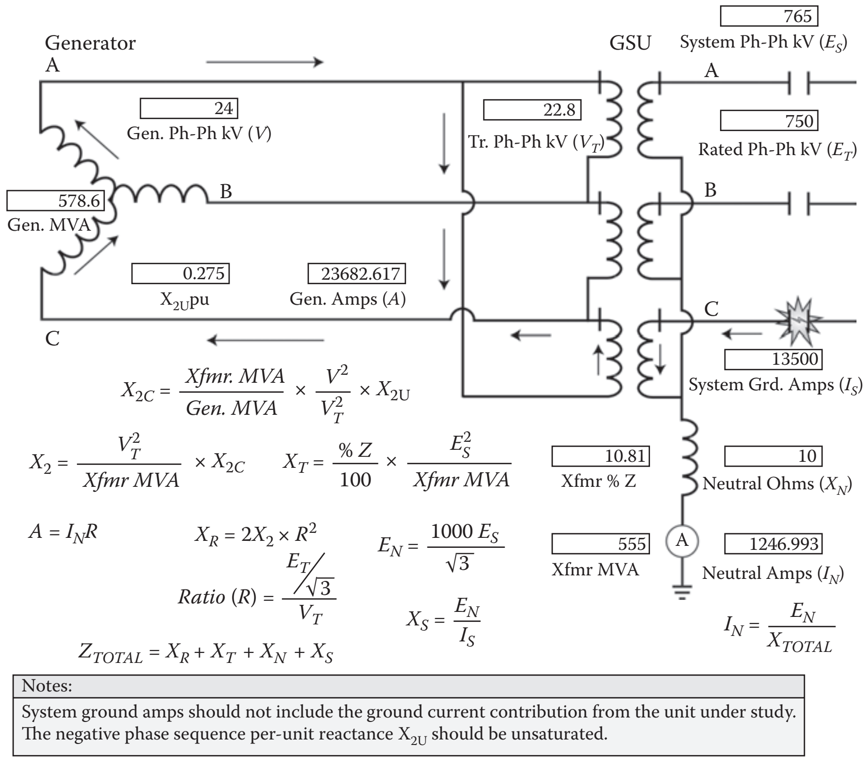


FIGURE 4.37
Pole Flashover Current

neutral symmetrical current can now be determined by dividing the system phase-to-neutral voltage by the total ohms. The transformer neutral current multiplied by the transformer winding turns ratio provides a generator side current of 23,683 amps or 170% of rated generator amps.

Normally, unit breaker pole flashover is detected by sensing GSUT neutral current and 52b logic that indicate that the unit breakers are open. Because the high voltage unit breakers are already open, it is necessary to initiate breaker failure protection to isolate the faulted circuit breaker. Where two unit breakers are involved, breaker failure logic should be able to determine which breaker has the current flow and trip, accordingly. Pole flashover is not of major concern with generator bus breakers because the ground current would be limited by the high impedance stator grounding scheme.

4.4.10 Overvoltage (59)

As the name implies, this function operates for generator 60 Hz overvoltage. Because the volts/Hz function also covers 60 Hz overvoltage, this writer does not normally place the 59 function into service.

4.4.11 Loss of Potential (60)

Normal practice is to prevent nuisance tripping from blown potential transformer fuse conditions. Older electromechanical relays compare one set of potential transformers to another set and block tripping of voltage sensitive relays that might actuate if the two sets of potential transformer outputs are not balanced. Newer digital schemes look at only one set of potential transformers, and if there is a 10% reduction in voltage with no change in generator current flow, a blown fuse is assumed; in addition to alarming, the 60 function will normally block tripping of the 21, 40, 50/27, 51V, and 78 functions. Protective functions that operate on increased voltages would not require blocking for blown fuse conditions and the under- and overfrequency elements normally require a minimum voltage for measurement purposes.

4.4.12 Stator Ground (64)

Generator stator ground protection is applied to protect generator stators and all other directly connected electrical apparatus on the output side from ground faults. This can include the primary windings of the main step-up, auxiliary and excitation transformers, associated buses, the generator bus circuit breaker, instrument transformers, and surge capacitors and arrestors. As discussed under the high impedance grounding section of Chapter 3, a grounding transformer is connected between the generator neutral and the station ground grid. High impedance (resistance) grounding is preferred because generators are not typically designed to carry large unlimited close in ground fault currents. The generator stator ground overvoltage relay is connected on the secondary side of the grounding transformer. This function is sometime referred to as a 59G instead of 64.

Relays used for this purpose are normally desensitized to the third harmonic voltages that appear on the neutral when the machine is energized. The voltages are caused by nonsymmetry in the core iron flux, which allows some areas to saturate as the sine wave approaches maximum. The saturation has an imperceptible flattening affect on the sine wave peak that produces the small third harmonic voltage at the generator neutral. The third harmonic frequency (180 Hz) timing is such that the contribution from each phase adds up in a manner to produce a continuous single-phase 180 cycle voltage. For simplicity, the generator can be visualized as a 180 Hz single-phase machine with distributed capacitance at each end, as illustrated in Figure 4.38. This allows the third harmonic current to flow through the output side capacitance and then through the grounding transformer and neutral capacitance in parallel to complete the circuit. Normally, only a few volts of third harmonic will appear on the secondary side of the grounding transformer. The exact level depends on generator design details and will vary as the machine is loaded with watts and vars. The absence of a third

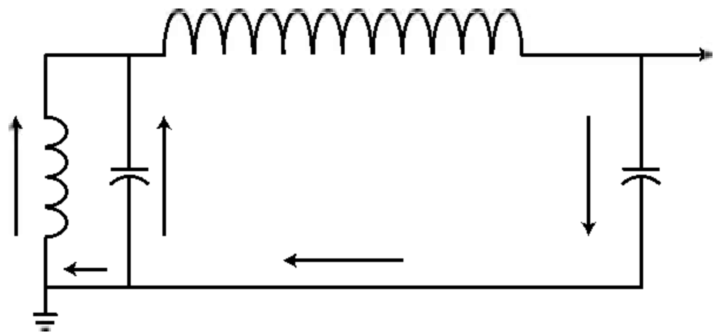


FIGURE 4.38
180 Hz Neutral Current Flows

harmonic voltage would indicate that either the machine has a ground on the neutral end of the winding, or it has an open or short in the primary or secondary ground detection circuitry. Consequently, it is a good idea to monitor the third harmonic voltage to prove that the ground detection scheme and generator are healthy.

Because the stator ground protection does not have the sensitivity to detect grounds that are located near the neutral (about 10% of the winding), schemes are available to trip or alarm on the loss of third harmonic voltage. The primary concern is that shorted stator turns near the neutral end will eventually degrade to ground faults from the high temperatures generated by the shorted turn current flow. This is much more of a problem for the slower speed salient pole hydro generators. The salient pole generators are designed with multi-turn stator slots (similar to large induction motors) that have relatively small levels of insulation between turns. Cylindrical rotor generators are designed with only two turns in a slot, and each turn has the full ground wall insulation capability, as illustrated in Figure 4.39. Accordingly, it is virtually impossible for transient voltages to cause turn-to-turn failures in cylindrical rotor generators and, consequently, most two and four pole machines are not equipped with surge capacitors. Some utilities trip on loss of third harmonics for hydro machines and alarm only for their two and four pole cylindrical rotor generators. Additionally, the ground wall insulation on a generator is not graded, and the neutral end, which operates at zero to approximately 10% voltage, has the same ground wall insulation (typically 95 kV BIL) as the output end, which operates at 100% voltage. Normal practice is to set the loss of third threshold at 50% of the no load third harmonic voltage. There have been cases with the 50% setting where loss of third harmonic protection schemes have tripped units off-line that were bucking vars or underexcited. Accordingly, it is preferable to alarm only for loss of third harmonic voltages on cylindrical rotor machines with an operating procedure that requires that the unit be taken off-line if an investigation discloses that the primary and secondary ground detection circuitry appears to be normal, that is, stator ground circuit

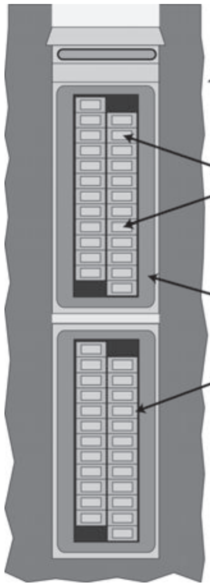


FIGURE 4.39
Cylindrical Rotor Generator Stator Coil Indirectly Cooled Construction

disconnects closed, grounding transformer racked-in, var output is boosting or shipping vars to the step-up transformer, and there is no measurable third harmonic voltage.

Generating stations built before the 1970s generally used open delta potential transformers for measuring bus potentials. Newer station designs usually apply wye-wye potential transformers to improve the integrity of the isolated phase buses. Each potential transformer is connected phase to ground, which negates the need to bring two different phases into the same segregated potential transformer compartment, maintaining the isolation and reducing the possibility of generator phase-to-phase faults. However, wye-wye connections with both primary and secondary neutrals grounded allows the stator ground protection scheme to detect secondary side ground faults. Either the stator ground protection time delay may need to be increased (at the risk of iron damage) to coordinate with potential transformer secondary side fuses, or the grounding method at the secondary side needs to be changed. Instead of grounding the secondary neutral point, one of the phases could be grounded with the neutral floating, as illustrated in Figure 4.40. The stator ground scheme can now only see faults between the secondary neutral and the grounded phase; because the neutral wiring is only between the transformer compartments, the exposure is quite low and a fault to the neutral is unlikely. The foregoing assumes that a grounded secondary side neutral is not required by the particular relays applied for generator protection.

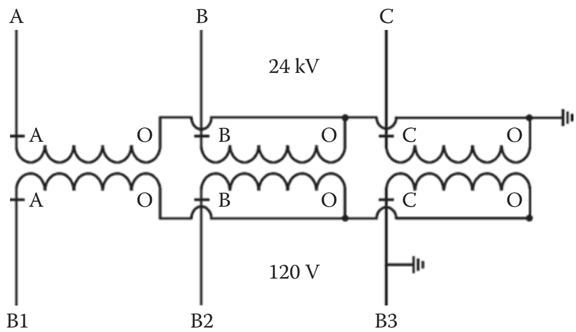
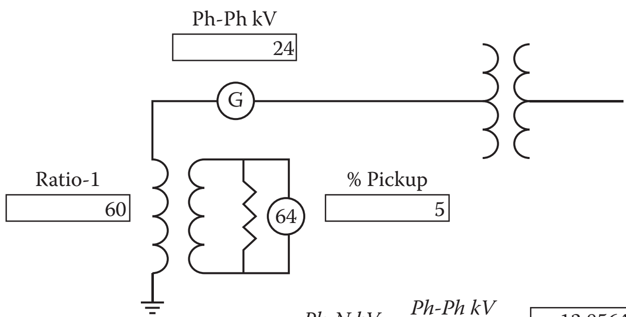


FIGURE 4.40
Modified Wye-Wye Potential Transformer Grounding



$$Ph\text{-}N\ kV = \frac{Ph\text{-}Ph\ kV}{\sqrt{3}} \quad \boxed{13.856406}$$

$$100\%\ Grd.\ Sec.\ Volts\ (E_s) = \frac{Ph\text{-}N\ kV \times 10^3}{Ratio} \quad \boxed{230.940100}$$

$$Pickup\ Volts\ Sec. = \frac{Pickup\ \%}{100} \times E_s \quad \boxed{11.547005}$$

$$Timing\ Volts\ Sec. = E_s \quad \boxed{230.9401}$$

$$Time\ Delay\ Seconds \quad \boxed{1}$$

Notes:
The suggested settings are set above typical third harmonic levels and are timed to mitigate stator iron damage from a grounded winding.

FIGURE 4.41
Stator Ground Relay Settings

Figure 4.41 provides suggested settings for the stator ground overvoltage tripping relay. A default minimum trip or pickup level of 5% of the 100% ground voltage is suggested, with a time delay of 1.0 second for a 100% ground fault. The pickup level should be higher than typical third harmonic voltage levels, to mitigate the possibility of nuisance tripping, and the timing is intended to mitigate the possibility of iron damage from low current prolonged ground fault conditions. Although most stator ground relays are desensitized to third harmonic voltages, many will still operate if the 180 Hz magnitudes are high enough. Additionally, there would also be concern over nuisance tripping if the harmonic filter degraded over time.

For designs that have generator breakers (between the generator and the step-up transformer), a second bus ground detector scheme will need to be installed after the generator breaker to provide ground detection and transient voltage mitigation from arcing grounds when the generator breaker is open. Because of the inability to coordinate the two ground detectors and the possibility of neutral instability or blown fuse problems with grounded wye–broken delta ground detector schemes, it may be advantageous that the second ground detector alarm only for ground conditions. If the generator stator ground scheme trips the unit off-line and the bus ground detector alarm does not clear, then the ground will be in or beyond the generator breaker; otherwise, it will be in the generator or generator side of the breaker. Because the grounded wye–broken delta scheme provides a zero sequence path, it will also detect the third harmonic voltage when the unit is on-line.

4.4.13 Out of Step (78)

Although there is concern with transient torques that can damage the turbine/generator/step-up transformer, out-of-step protection is primarily applied to protect turbine/generators from loss of synchronization or out-of-step slip frequency pulsating torques that can mechanically excite the natural frequencies of rotating systems. Each subsequent cycle can raise the shaft natural frequency torsional levels higher, eventually resulting in cycle fatigue failures if allowed to continue. Slip frequencies for out-of-step events are usually in the range of 0.5 to 5 cycles per second.

When an electrical short circuit occurs on the electrical system, a generator's watt load is displaced with vars that feed the fault. This, in effect, unloads the machine, and the turbine speeds up. If the electrical system protection does not clear the fault quickly enough, the generator can lose synchronization (dynamic instability) as the speed and associated phase angle differences increase in magnitude. This condition is aggravated by the opening of line breakers that increase the power transfer impedance. Dynamic instability usually occurs when the power angle differences are 120 degrees or greater. A three-phase fault unloads the machine the most and will have the shortest critical clearing time or time before it loses synchronization with the electrical system and becomes unstable—usually in the range of 6 to 20 cycles. At the other extreme are phase-to-ground faults, which only unload one phase; consequently, the critical clearing times can be 3 times longer in duration than in three-phase events.

Electrical faults will normally move to a specific impedance point and stay there until cleared by automatic protective relaying. An out-of-step condition

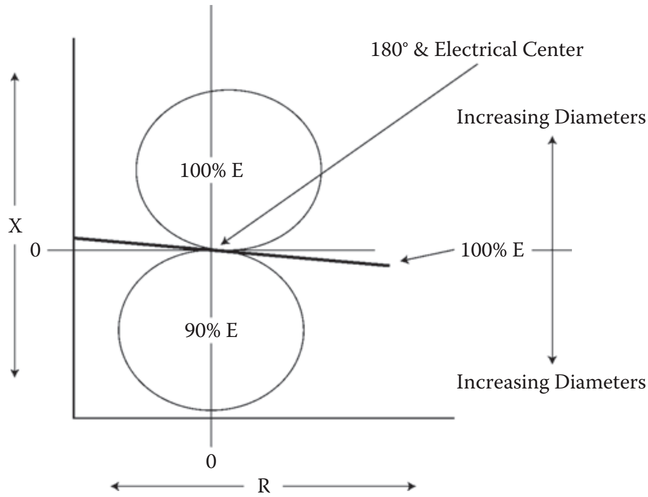
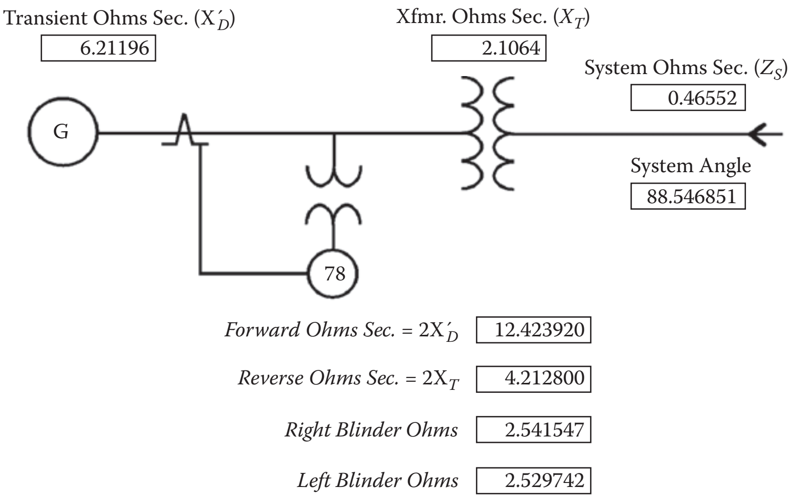


FIGURE 4.42
Out-of-Step Swing Impedance

results in a traveling impedance swing or locus that moves through a supervising mho circle repeatedly until synchronization is restored or the generator is tripped off-line. Figure 4.42 illustrates typical impedance swings; the voltage at the machine terminals determines var flows during the swing and a relatively lower generator voltage will result in leading vars into the machine. The electrical center for a typical utility system is normally in the generator or its associated step-up transformer. The center is the total impedance divided by 2 and occurs when the two systems are 180 degrees out; it appears as a momentary three-phase fault to both the generator and the system.

Figure 4.43 develops the settings for a single blinder scheme, which is simpler to set and more common than other designs. By convention, forward is toward the generator and the reverse reach is toward the electrical system. The suggested forward reach for the offset mho circle is 2 times the generator transient reactance to ensure, with margin, that the generator is covered. The suggested reverse reach is 2 times the step-up transformer impedance to ensure that the transformer and part of the electrical system are covered. For cross-compound units or generators operated in parallel, the reverse reach will need to be modified to account for infeed impedance.

The right and left vertical impedance blinders are set for 120 degrees (extrapolated power angles) or 60 degrees on each side of a perpendicular bisect line of the vector sum of the generator, transformer, and system impedances (electrical center), as illustrated in Figure 4.44. By convention, the generator and step-up transformer are assumed to be purely inductive, and only the impedance angle for the system is considered. The settings are normally determined with a time-consuming graphical procedure, but the

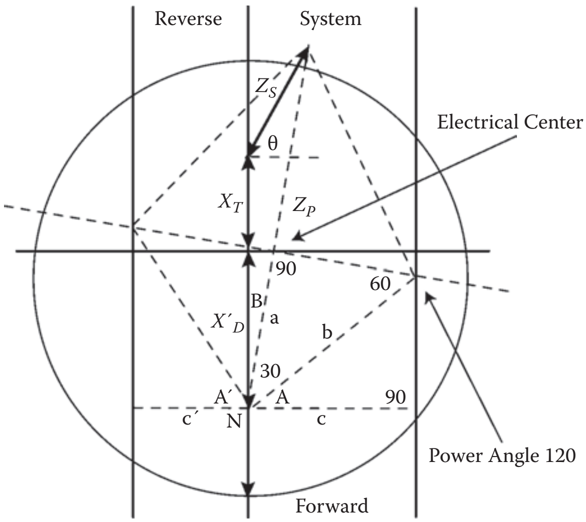


Notes:

All ohms are generator base secondary. By convention, forward is toward the generator and reverse is from the generator to the system. Normally, single blinder schemes are not concerned with the speed of the impedance swing and time settings to capture the event are not required. The suggested settings will capture swings that are within the supervising mho circle. The electrical center for modern utility systems is usually in the generator or its step-up transformer. However, for relatively weak electrical systems, a stability study may be needed to insure that the impedance swing is not outside the reach of the mho circle.

FIGURE 4.43
Out-of-Step Single Blinder Relay Settings

figure provides a trig method for calculating blinder settings. In reference to Figure 4.44, the right blinder reaches very far to the left and the left blinder reaches very far to the right. Assuming that the swing is approaching from the right side, the left blinder will already be picked up from load current and will see the event first, followed by the supervising mho circle. As it continues to travel, it will actuate the right blinder, then drop out the left blinder, and finally exit the mho circle on the left side, completing the cycle. Tripping is normally initiated upon exiting the mho circle. If the swing originates from the left side, a reverse sequence will take place, and tripping will occur when the swing exits the supervising mho circle on the right side. Other schemes are available, but the single blinder scheme is one of the simplest as it does not require slip frequency data or concern about the speed of the swing. Because tripping is initiated at the exit of the mho circle when the impedance is higher, the interrupting current levels for generator breakers should be favorable, depending on the breaker tripping time and the slip cycle frequency. Accordingly, tripping time delay is not normally provided unless studies have been performed that indicate that a time delay should be provided to reduce the interrupting current of the generator breaker. This, of



$$\textit{If Theta} = 90 \textit{ then } Z_P = X'_D + X_T + X_S$$

$$\textit{Right and Left Blinders} = 0.5b$$

$$Z_P = \sqrt{(Z_S^2 + (X'_D + X_T)^2) - (2Z_S\,(X'_D + X_T)\;Cos\,(\theta + 90))}$$

$$a = 0.5Z_P \qquad b = \frac{a}{Sin\,(60)} \qquad B = Arcsin\left(\frac{Sin(\theta + 90) \times Z_S}{Z_P}\right)$$

$$A = 90 - (B + 30) \qquad A' = 90 - (30 - B)$$

$$\textit{Right Blinder } (c) = bCosA \qquad \textit{Left Blinder } (c') = bCosA'$$

FIGURE 4.44
Out-of-Step Blinder Calculations

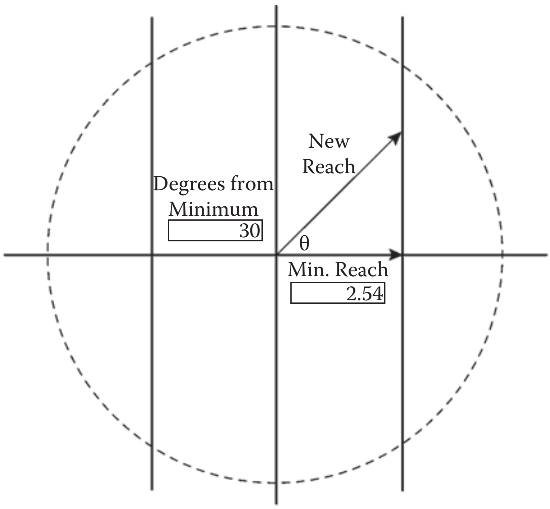
course, is dependent on generator breaker tripping time, the electrical system configuration, generator loading, and associated inertia and impedance parameters that influence slip frequencies at the time of the event.

Figure 4.45 shows the calculation for determining different reach points for right or left blinders. This is useful for analyzing events and also for testing the out-of-step blinder elements.

As a matter of interest, a similar calculation is shown in Figure 4.46 to determine different reach points for a reactance type impedance element. Reactance elements are sometimes used to cut off mho circles to mitigate overreaching on short transmission lines.

4.4.14 Overfrequency and Underfrequency (81)

Generator overfrequency and underfrequency relays are normally applied to protect turbine blades from resonant frequencies during off-frequency



$$New\ Reach = \frac{Min.\ Reach}{Cos\theta} \quad \boxed{2.932939}$$

Notes:
Useful for testing or analyzing different vertical blinder reach points.

FIGURE 4.45
Vertical Blinder Impedance Points

operations. The turbine blade frequency withstand times are cumulative, and damage can occur when the withstand times are used up. The longer low pressure steam turbine blades are normally more sensitive to off-frequency operation. Turbines blades that are under stress (at full load) may resonant at different frequencies than those of unloaded blades, and the unit load at the time may impact the withstand time. On typical utility systems, off-frequency operation events are not numerous and the durations are normally quite short. Although under- and overfrequency resonant limitations are generally mirror images, with the exception of more severe overspeed conditions where centrifugal force becomes the major limitation, the primary concern is really underfrequency, where governor action alone cannot mitigate the occurrence. Underfrequency occurs when the generation does not match the load. If the load is higher than the available generation, the system frequency will decay as the turbines slow down. Utilities normally have underfrequency load shedding programs that will isolate blocks of load in an effort to rebalance available generation with the load demand. Governor action on the generating units will also open steam or fuel valves, but they have limited capability on the amount of additional load that they can pick up. Motors will also slow down; this reduces customer load demand but may also have a reducing impact on generating station output levels. Many generating stations are not equipped with overfrequency and underfrequency tripping and rely on operations to take generating units off-line at

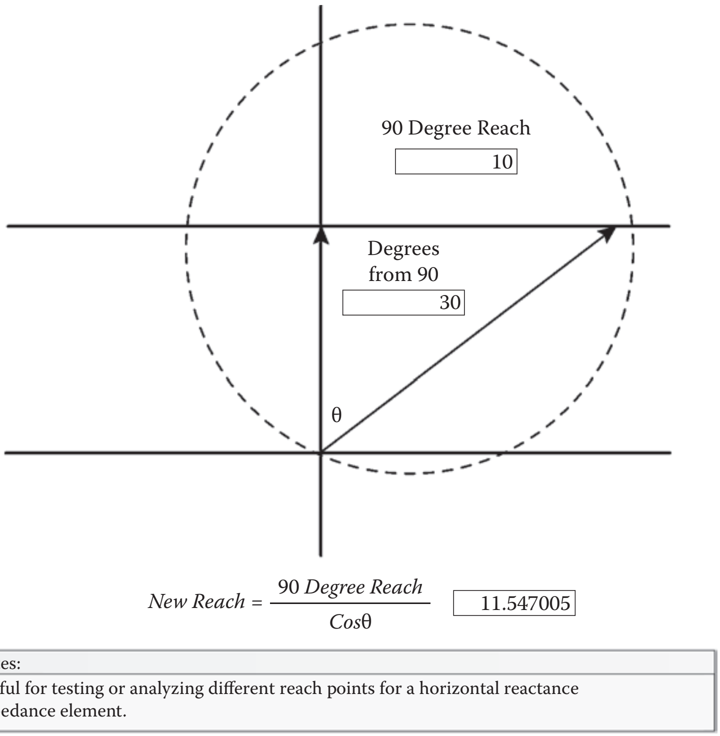
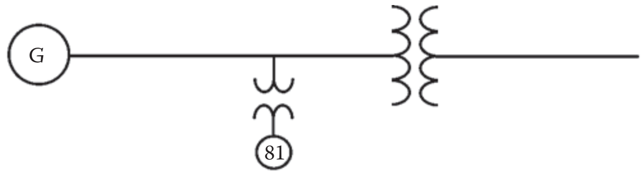


FIGURE 4.46
Horizontal Reactance Supervision

57 Hz if the frequency does not show signs of recovering. By 57 Hz, the utility underfrequency load shedding program has already done what it could to balance load, and other automatic load shedding programs are not typically available to reduce load further. There is also a concern that the generating unit could be isolated with excessive load if other units trip off first, causing significant turbine/generator stationary and rotor torsional forces as the machines are forced to abruptly slow down.

Figure 4.47 provides preliminary settings if information is not available from the turbine manufacturer or the regional transmission authority. The preferred method is to solicit recommendations from the turbine manufacturer, who should have specific knowledge about the frequency limitations of their equipment. The settings provided in Figure 4.47 will allow a single event to consume approximately 50% of the ANSI composite large steam turbine accumulated withstand times before tripping the unit off-line and should coordinate with typical utility underfrequency load shedding programs.

Because potentially damaging events are somewhat rare and normally short in duration, and the underfrequency tripping functions need to coordinate with utility load shedding programs and governor control responses



Set Point 1 Frequency	58.5	Set Point 4 Frequency	61.5
Set Point 1 Delay Seconds	300	Set Point 4 Delay Seconds	300
Set Point 2 Frequency	57.8	Set Point 5 Frequency	62.2
Set Point 2 Delay Seconds	90	Set Point 5 Delay Seconds	90
Set Point 3 Frequency	57.2	Set Point 6 Frequency	62.8
Set Point 3 Delay Seconds	7	Set Point 6 Delay Seconds	7

Notes:
These settings should coordinate with typical utility load shedding programs. Depletes approximately 50% of the ANSI composite withstand for large steam turbines. See ANSI C37.106 for additional information. Consult with turbine manufacturer for more refined settings.

FIGURE 4.47
Overfrequency/Underfrequency Withstands

to mitigate unnecessary tripping that can aggravate system disturbances, the suggested time delays are somewhat long in duration. The over- and underfrequency settings are really a compromise between the generating station, the original equipment manufacturer (OEM), and the utility. Turbine manufacturers often take a conservative approach to ensure protection of their equipment and may deny warranty unless the recommended over- and underfrequency tripping is implemented. This can put the generating station in conflict with the utility because the manufacturer's initial recommendations may not coordinate with the utility underfrequency load shedding program. The utility may not allow the generation company to connect to their system unless the underfrequency tripping coordinates with their program. Sometimes an iterative process takes place before the manufacturer, generating station and the utility can compromise on the over- and underfrequency settings.

In more recent years, regional transmission authorities in the United States have recommended settings that manufacturers can use as a guide for their turbine withstands and utilities can use for coordinating their load shedding program.

In 2003, Western Electricity Coordinating Council (WECC), a Western U.S. regional transmission authority, recommended not tripping faster than the following durations at the associated frequencies:

- > 59.4 and < 60.6—continuous
- 59.4 and 60.6—3 minutes
- 58.4 and 61.6—30 seconds

- 57.8—7.5 seconds
- 57.3—45 cycles
- 57 and 61.7—instantaneous trip

Usually generator multifunction digital relays do not provide more than six over- and underfrequency elements. Accordingly, applying the WECC shortest allowable time delays, (assuming they are required to be within the turbine manufacturer's recommendations), and trying to prioritize the six available set points, the following trip settings are suggested:

- 58.4 Hz—30 seconds
- 57.8 Hz—7.5 seconds
- 57.3 Hz—.75 seconds
- 57.0 Hz—0.1 seconds
- 61.6 Hz—30 seconds
- 66.0 Hz—0.1 seconds

The withstand time for events higher than 58.4 or lower than 61.6 are long enough to rely on operator intervention. A short time delay of 6 cycles is provided at 57 Hz to try and avoid nuisance tripping from spurious events. The last or remaining element is used to back up the mechanical overspeed trips for a steam unit that is normally set for 10% overspeed. A time delay of 0.1 seconds is also provided to mitigate spurious tripping.

4.4.15 Lockout Relay (86)

The foregoing tripping functions discussed in this chapter drive 86 lockout auxiliary relays that have isolated contacts for tripping and alarming. Several contacts are required to trip the prime mover, excitation system, unit auxiliary transformer, and unit breakers and initiate appropriate annunciation or alarms to guide operations. Tripping should be done in a manner that limits the unit exposure to overspeed, underexcitation, and overexcitation (volts/Hz) and completely isolates the particular failure. The more common practice is to provide at least two 86 lockout relays and split the functions between the relays to provide some form of redundancy, that is, unit differential on one lockout relay and generator differential, transformer sudden pressure, backup zone 1 impedance, and switchyard zone 1 impedance on the other. As mentioned before, the normal unit differential zone of protection for high current short circuit conditions is in between the generator neutral point and the high voltage unit breakers. The relays that are driving the other lockout relay will also detect faults in that zone of protection.

4.4.16 Generator Differential (87)

Almost all generators 10 MVA and larger are equipped with neutral and output side CTs for differential protection. Differential protection in general was covered in Chapter 3. In the case of generators, the relay (secondary side) tripping thresholds at low loads are very sensitive and usually in the 200 to 300 milliamp range to mitigate iron damage. The differential function cannot detect shorted stator turns because the current in equals the current out. As mentioned earlier, this is more of a concern with the slower speed salient pole hydro machines and shorted turns are not that likely with the two and four pole cylindrical rotor machines due to their robust stator coil design. The differential scheme does not normally have the sensitivity to detect ground faults on generators that are high impedance (resistance) grounded. One concern with generator differential is the very high fault current levels, and the installation of CTs with like characteristics is more important to prevent nuisance tripping from through fault conditions. Typical slopes for generator differentials are in the 10% to 25% range.

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5

Electrical Apparatus Calculations

This chapter presents miscellaneous electrical apparatus calculations that have not been covered in the proceeding chapters. The calculations and text are useful for electrical engineers engaged in support of operations, maintenance, and betterment projects for generating stations and other industrial plants.

5.1 Buses

Buses need to be able to withstand short circuit currents from external or through faults without damage or loss of life. In addition to thermal withstands, they need to be supported in a manner to handle the magnetic bending forces that occur from high magnitude short circuit currents. Figure 5.1 shows the formulas for calculating peak forces for horizontal bus bars only.

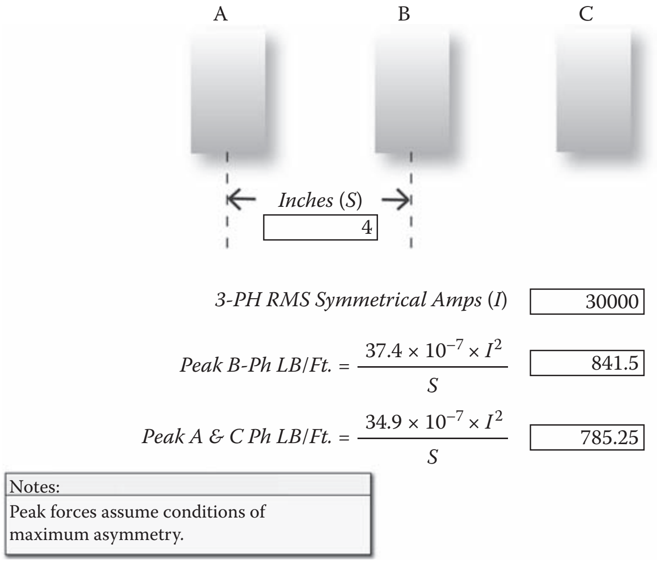


FIGURE 5.1
Horizontal Bus Bar Forces

The calculation expressions need to be modified for vertical bus bars to consider gravitational effects and for bus bars that bend in a different direction. Only the horizontal forces are considered here to provide the reader with some understanding of the magnitude of electromechanical forces. The expressions assume maximum asymmetry and determine the peak forces. As shown, the forces for B phase or the middle bar are higher because both of the other phases are in close proximity and act on the middle phase.

The forces cause vibration at double frequency or 120 hertz (Hz) because of the change in polarity during each half cycle. B phase experiences 841.5 foot pounds for each foot of unsupported length. At first blush, this does not seem like much force for such a high current level with a relatively short separation distance between bars. However, imagine an 800 pound weight swinging or oscillating at 120 cycles per second.

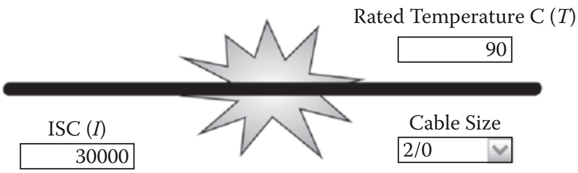
5.2 Cable

5.2.1 Withstand Seconds

The cable withstand calculation is used to verify that protective relay systems will clear through faults or external short circuits before damage occurs to cables. Figure 5.2 determines the number of seconds and cycles that a cable can withstand a high current level before damage occurs. For example, you would not want to replace the cables if a 4 kilovolt (kV) motor developed a short circuit condition. Normally, it is assumed that the cables are at rated temperature when the fault occurs. The calculation then determines the number of seconds and cycles that it will take to reach a conductor temperature of 250°C, which is the annealing point of copper and considered the maximum temporary withstand temperature for copper conductors before loss of life or damage occurs. As you can see in the figure, 2/0, 90°C cable can only withstand 30,000 amps for 0.1 seconds or 6 cycles before reaching 250° C. Because instantaneous fault interruption is usually considered to be around 6 cycles, and 30,000 amps is a typical 4 kV three-phase fault current level, 2/0 cable would not provide sufficient design margin. Consequently, many engineering firms will not use cable that is smaller than 4/0 for 4 kV applications in large generating stations.

5.2.2 Fusion Seconds

Figure 5.3 covers the amount of time a cable can carry a high level of current before the copper conductors fuse open. One useful application for this calculation is to determine how long a personal ground will last during an inadvertent energization. This is important because safety grounds cannot



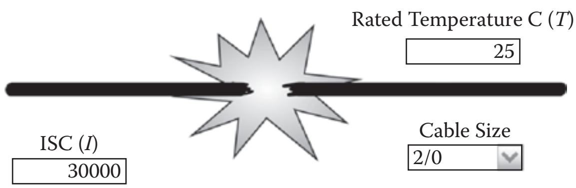
$$Withstand\ Seconds = \frac{0.0297\ Log\left(\dfrac{250 + 234}{T + 234}\right)}{\left(\dfrac{I}{A}\right)^2} \quad \boxed{0.101899}$$

$$Withstand\ Cycles = Seconds \times 60 \quad \boxed{6.113940}$$

Notes:
For additional information see Insulated Power Cable Engineers Association (IPCEA) data.

A = *Circular Mills*

FIGURE 5.2
Cable Withstand Seconds



$$Fusing\ Seconds = \frac{0.0297\ Log\left(\dfrac{1084 + 234}{T + 234}\right)}{\left(\dfrac{I}{A}\right)^2} \quad \boxed{0.413098}$$

$$Fusing\ Cycles = Seconds \times 60 \quad \boxed{24.78588}$$

Notes:
For additional information see Insulated Power Cable Engineers Association (IPCEA) data.

A = *Circular Mills*

FIGURE 5.3
Cable Fusion Seconds

protect personnel from inadvertent energizations unless they are able to last longer than it takes for the protection to automatically de-energize the circuit. In this case, the personal grounds are assumed to be at ambient temperatures initially or 25°C. The calculation then determines the number of seconds and cycles that it will take to reach a conductor temperature of 1084°C or the fusion or melting point for copper. As shown in the figure, 2/0 cable can only withstand 30,000 amps for .413 seconds or 24.79 cycles before the conductors fuse open and can no longer provide safety protection. This limitation may be of concern for switchgear personal safety grounds as transformer secondary side overcurrent protection usually takes longer than 0.4 seconds to interrupt short circuit conditions. Consequently, larger personal ground conductors or parallel cables may be required to provide adequate safety protection.

5.2.3 Line Loss

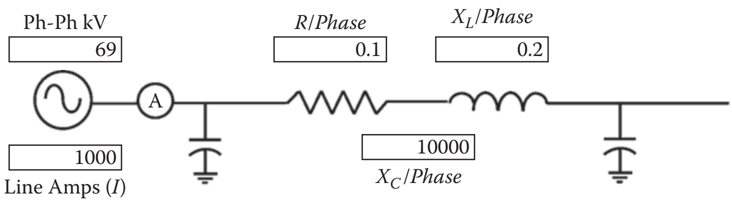
The line loss calculation is used to determine the amount of watt loss and var consumption of underground and overhead cables. It is useful for economic and voltage analysis of overhead/underground lines and for verifying the accuracy of revenue meters that are compensated for line losses to upstream or downstream points of delivery. Usually a conductor temperature of 50°C is assumed for determining the resistance of overhead conductors for revenue metering applications.

The calculation procedures are shown in Figure 5.4. Basically, the watt loss for balanced conditions can be determined by squaring the current in one phase, multiplying it by the resistance of one phase, and then multiplying it by 3 to include the losses from the other phases. The net var consumption can be determined with a somewhat similar procedure. First, the squared line current is multiplied by the inductive reactance ohms times 3 to obtain the total inductive vars. Then, the square of the phase-to-neutral voltage is divided by the capacitive reactance per phase and then multiplied by 3 to determine the total capacitive vars. Finally, the total or net vars are determined by subtracting the capacitive vars from the inductive vars. A negative result means that the line is predominantly capacitive at the specified line current. Predominantly capacitive vars will cause a voltage rise in the line that can be calculated according to the formulas presented in Chapter 2.

5.3 Switchgear Circuit Breakers

5.3.1 Alternating Current (AC) Hi-Pot Testing

The routine AC overvoltage or hi-pot testing of medium voltage switchgear circuit breaker insulation systems is strongly recommended based on typical



$$Watt\ Loss = I^2 R \times 3 \qquad \boxed{300000}$$

$$E = \frac{kV \times 10^3}{\sqrt{3}}$$

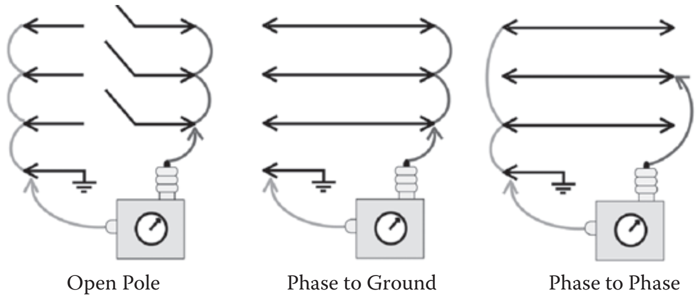
$$Vars = (I^2\,\mathrm{X_L} \times 3) - \left(\frac{E^2}{X_\mathrm{C}} \times 3\right) \qquad \boxed{123900}$$

Notes:
50°C is typically used to determine the resistance of overhead conductors for revenue metering compensation of transmission line losses.

FIGURE 5.4
Cable Line Loss

failure modes, the inability of a lower voltage megger insulation test to always identify the problem area, the low cost for the test equipment, the low cost to repair a failure, and finally and most important, the potential hazard to operating personnel who rack the breaker into the cubicle while standing in front of it, which energizes approximately one-half of the breaker. AC testing is preferred over direct current (DC) because of the physical geometries of the equipment. Switchgear circuit breakers have very little capacitance and, consequently, AC hi-pot sets can be very small in size and capacity and relatively inexpensive. Insulation failures are usually the result of surface tracking; thus they can be repaired easily. Because the consequence of a test failure is relatively minor, electricians can perform the testing when they overhaul the breaker. By comparison, the DC hi-pot testing of medium voltage motors and medium to large generators are normally performed by highly trained engineers or technicians and often witnessed by a supervisor or engineer because of the high cost of failure.

Figure 5.5 illustrates the three overvoltage tests that should be performed routinely on switchgear circuit breakers and provides recommended routine test values. An open pole test is performed to verify that the arc chutes are not overly contaminated from interrupting arc by-products and also to test the movable contact insulation to ground in the open position. The phase-to-phase test verifies the integrity of the phase-to-phase insulation, and the phase-to-ground test proves that the ground insulation level with the breaker closed is acceptable for continued service.



Breaker Rated kV: 4

Routine Test AC kV (75%): 14.25

Nominal Breaker kV	Factory AC kV Test
0.6	2.2
4.16	19
7.2	26
13.8	36
14.4	50
23.0	60
34.5	80

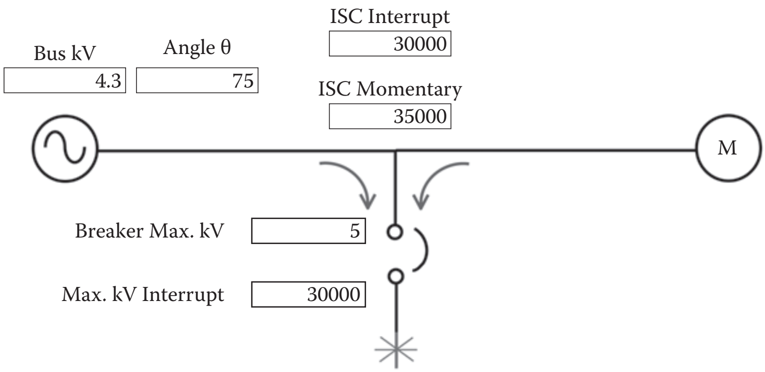
Notes:
Routine AC hi-pot tests are normally performed at 75% of factory test. See (Elecrtical Power Research Institute) "Power Plant Electrical Reference Series", Volume 7, for additional information.

FIGURE 5.5
Circuit Breaker AC Hi-Pot Testing

5.3.2 Circuit Breaker Duty

Switchgear circuit breakers have two ratings for short circuit currents. The interrupting rating is the maximum asymmetrical current that the circuit breaker can interrupt without damage. The momentary rating is the maximum asymmetrical current that the breaker can close into and mechanically latch. In either case, interrupting or momentary, the resulting high temperature arcing, if long enough in duration, will cause severe damage to the circuit breaker.

Figure 5.6 presents the procedure for calculating the breaker interrupting and momentary asymmetrical currents for breakers manufactured from the mid-1960s to 2000. Verification on which standard was used by the manufacturer should be made for breakers built near the ends of the foregoing year range. In recent years, the standards have been leaning more toward vacuum breaker technology instead of air circuit breakers, and they are also being merged with the European standards. As illustrated in the Figure 5.6, current



$$Adjusted\ CB\ Interrupt\ Rating = Max\ Int.\left(\frac{Max\ kV}{Bus\ kV}\right) \quad \boxed{34883.721}$$

$$Z = \frac{Bus\ kV \times 10^3}{\sqrt{3}\ ISC\ Int.} \qquad R = ZCos\theta \qquad X = ZSin\theta$$

$$X/R\ Ratio = X/R \quad \boxed{3.732}$$

Interrupt factor (F) extrapolated from ANSI/IEEE C37.010
X/R Curves (Remote source, 5 cycle CB, 3 cycle contact part)

$$Asymmetrical\ ISC\ Interrupt = F \times ISC\ Interrupt \quad \boxed{30000}$$

$$Asymmetrical\ ISC\ Momentary = 1.6 \times ISC\ Momentary \quad \boxed{56000}$$

Notes:
Symmetrical current calculation procedure for switchgear breakers manufactured under ANSI/IEEE standards from 1964 to 2000.

FIGURE 5.6
Circuit Breaker Duty

from the source transformer and motors will flow through the breaker. If the breaker in question feeds a motor, the contribution from that motor does not need to be considered. Normally, a load breaker that feeds a downstream transformer would represent the worst-case position for the study, or the smallest motor if transformer feeders are not provided in the design. The motor contribution is breaker specific, and the source breakers do not see the motor contribution from the bus that they are feeding.

The source transformer and motor symmetrical short circuit contributions and the summing of currents from two sources were discussed in Chapter 2. Prior to beginning this calculation procedure, the transformer three-phase symmetrical short circuit current is paralleled with the motor symmetrical interrupting current and then again with the motor symmetrical momentary current to determine the total (transformer + motor) interrupting and momentary symmetrical values, respectively.

Normally, the circuit breaker maximum interrupting current is given at the maximum rated kV. If the bus is operating at a lower kV, you can take advantage of it and increase the interrupting rating by a factor of maximum kV/bus kV. Then, the total interrupting short circuit impedance is calculated, and the X/R ratio is determined from the angle. The X/R ratio is used to estimate the asymmetrical interrupting current decrement at the time the circuit breaker contacts part. Figure 5.6 assumes that the breaker trips open in 5 cycles and the contacts part in 3 cycles. If the contacts take longer to part, the asymmetrical current may be lower and conversely if they part faster, the current may be higher. If the circuit breaker does not appear to have sufficient margin and the breaker trip and contact part times are different, a more precise interrupt factor should be extrapolated from the ANSI/IEEE X/R curves presented in C37.010. The momentary rating assumes asymmetrical currents of 1.6 per unit or 160%, as the event is instantaneous and there is no time for decay. The ANSI/IEEE remote source indicated in the figure means that generator sources are distant enough that the generator current decrement does not need to be considered. Generator decrement does not need to be considered if the fault impedance is larger than the remote generation impedance by a factor of 1.5 or greater.

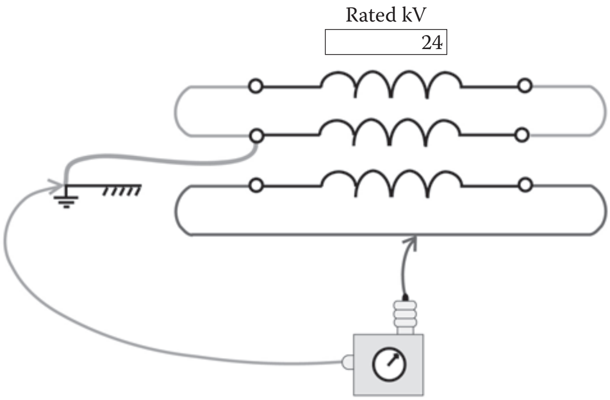
When the available short circuit duty is too high for the circuit breaker ratings, there are a number of mitigation methods. From the least expensive to the most, these include using motor feeder cables in the calculation, using actual locked rotor currents instead of maximum nameplate values, limiting the available ground current (if that is the problem area), adding a few cycles of time delay to instantaneous overcurrent circuit breaker tripping (if asymmetrical interrupting current is the problem), relocating some motors to other buses, upgrading selected feeder breakers, installing phase reactors, and installing higher impedance transformers.

5.4 Generators

5.4.1 Acceptance Direct Current (DC) Hi-Pot

Insulation systems for medium voltage generator stators are normally DC overvoltage or hi-pot tested at acceptance values after shipment or installation, or following rewinds when another party is responsible for the cost of repair and to also prove that the apparatus is fit for service. DC is used instead of AC because of the amount of vars needed to support the insulation capacitance. The relatively high AC var load in comparison to DC necessitates the need for a high capacity large AC hi-pot test set that is relatively expensive and difficult to transport to the site. Normally, one phase is tested at a time with the other two phase grounded. The ends of the coils are connected together to reduce transient voltages in case the test is suddenly interrupted.

Generator Acceptance DC Hi-pot



Factory Text kV = ((2 × Rated)+1) × 1.7 $\boxed{83.3}$

Acceptance Test kV = *Factory Test* × 0.85 $\boxed{70.805}$

Notes:
For additional information, see ANSI/IEEE standards: 95-1977, 115-1983, 433-1974, C50.10-1977 and NEMA MG 1-1978.

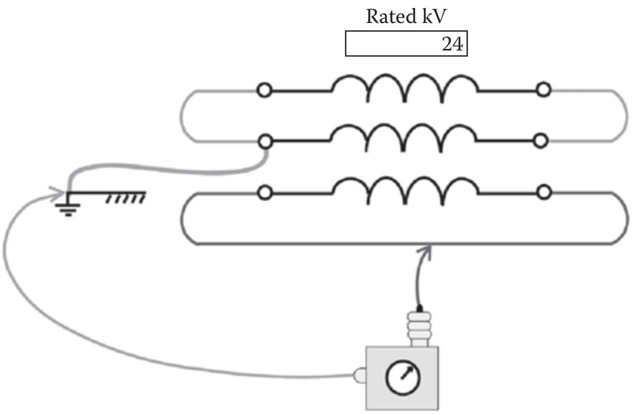
FIGURE 5.7
Generator Acceptance DC Overvoltage Testing

Figure 5.7 provides recommendations on DC acceptance test kV levels. Numerous standards address this matter, as shown in the notes section of the figure. The AC factory test is performed at twice rated phase-to-phase kV plus 1 kV. Acceptance tests are normally performed at 85% of the factory value. The AC value is then multiplied by 1.7 to convert it to an equivalent DC magnitude. This is not a conversion from RMS to peak and was determined by industry consensus that a 1.7 factor provides an equivalent DC searching level.

5.4.2 Routine DC Hi-Pot

Insulation systems for generator stators are normally routine DC overvoltage or hi-pot tested during unit overhauls or major outages to provide a measure of confidence that the insulation will perform its intended job until the next overhaul.

Figure 5.8 provides recommended kV values for the routine DC overvoltage of testing of generators. Most manufacturers feel that a test level of 125% to 150% of the phase-to-phase voltage is high enough to predict a future life. A value of 125% of the rated phase-to-phase voltage multiplied by 1.7 for the DC equivalency is suggested as it is more defendable in case the insulation system fails to carry the voltage. A turn failure in the stator slot areas



% Rated kV 125

$$DC\ Hi\text{-}Pot\ kV = \frac{Rated\ kV \times \%Rated}{100} \times 1.7 \quad 51$$

Notes:
Most generator manufacturers recommend 125% to150% of rated kV for suitability for continued service tests.

FIGURE 5.8
Generator Routine DC Overvoltage Testing

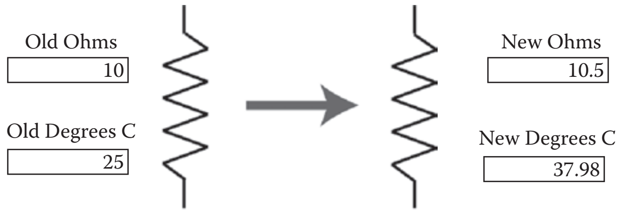
normally requires a partial or full rewind. If you elect not to overvoltage test during a major outage and the insulation fails shortly after returning the unit to service, you may not be in a defendable position.

5.4.3 Temperatures

Figures 5.9 and 5.10, present the formulas for determining temperature based on copper resistance and also resistance based on temperature. The formula will work on any copper winding.

Generator and larger medium voltage motor stators normally have 10 ohm copper resistance temperature devices (RTDs) embedded in the stator windings and in gas passages to monitor stator temperatures. Usually, the RTD will have an ohmic value of 10 at 25°C. Where applied, these devices can drive recorders, protective relays, or distributed control systems (DCS) and alarm or trip if the temperature reaches the set point value. As you can see in Figure 5.9, a resistance value of 10.5 ohms would indicate a temperature of 38°C.

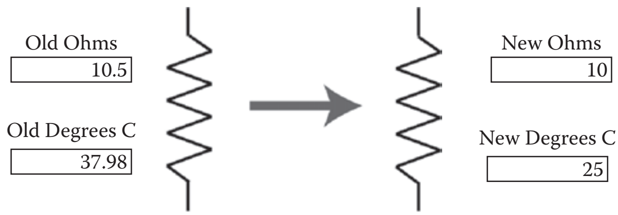
A similar approach can be used to determining the temperature of a generator's rotating field that is equipped with collector rings and brushes. The resistance of the field can be determined by dividing the field voltage (allowing for brush voltage drop) by the field current. This is one of the most important measurements for monitoring the health of the generator and is



Notes:
R_1 = Old Ohms
T_1 = Old Degrees C
R_2 = New Ohms
T_2 = New Degrees C

$$T_2 = \left(\frac{R_2(234.5 + T_1)}{R_1}\right) - 234.5$$

FIGURE 5.9
Copper Ohms to Degrees Centigrade



Notes:
R_1 = Old Ohms
T_1 = Old Degrees C
R_2 = New Ohms
T_2 = New Degrees C

$$R_2 = \left(\frac{R_1(234.5 + T_2)}{234.5 + T_1}\right)$$

FIGURE 5.10
Degrees Centigrade to Copper Ohms

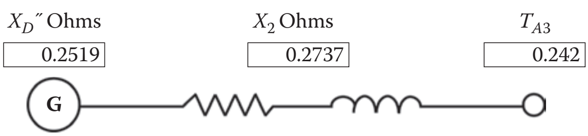
often overlooked when replacing recorders with a DCS. In addition to monitoring the temperature of the rotor, it can provide a number of other indications. If the temperature suddenly increases, it can indicate brush-rigging problems that can add resistance to the circuit or a bad connection in the axial studs or main leads to the field windings. A sudden drop in temperature could be an indication of shorted field turns.

The field temperature measurements can also help operations in determining the appropriate action for field ground alarms. An internal generator field ground could be caused by high temperature electrical arcing, insulation damage, contamination, elongated end turn conductors, brush-rigging problems, or other anomalies in the generator field. If a second ground occurs inside or outside the field in the opposite polarity, DC short circuit currents will flow that can damage the rotor forging, retaining rings, collector rings, journals, and bearings. For that reason, manufacturers normally recommend automatic tripping for field ground events. Generating stations usually elect not to trip automatically because experience has shown that the ground is usually located in the peripheral excitation equipment and not in the generator rotor and, consequently, the risk or exposure to the rotor may be low. However, if the field ground is coincident with step changes in either generator bearing vibration or field temperature, then the probability of the ground being in the rotor is quite high and the unit should be quickly removed from service to mitigate the possibility of rotor damage.

5.4.4 X/R Ratio

Large generators are usually assumed to be purely inductive. However, if a more refined study is desired, the generator's X/R ratio needs to be known so that a more precise short circuit angle can be calculated. Generators 40 MVA and larger will typically have X/R ratios that range from 40 to 120, and smaller 1 to 39 MVA machines usually have X/R ratios that range from 10 to 39. Smaller X/R ratios have lower short circuit angles, which cause asymmetrical currents to decay more rapidly.

Figure 5.11 illustrates a procedure for calculating generator X/R ratios for the 60-Hz generator in Chapter 4. Three parameters are needed for the calculation: the direct axis saturated subtransient reactance (X_d''), the saturated negative phase sequence reactance (X_2), and the generator armature time constant (Ta_3). The effective R can then be calculated by using the formula presented in the figure. The calculated R can then be backed out of the subtransient reactance to determine the X/R ratio.



$$Effective\ R = \frac{X_2}{2\pi\, 60 T_{A3}} \quad \boxed{0.003}$$

$$X = \sqrt{X_D''^2 - R^2}$$

X/R Ratio $\boxed{83.959}$

Notes:
See ANSI/IEEE C37.010 for additional information.

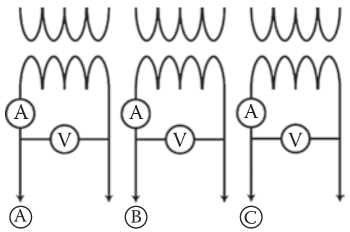
FIGURE 5.11
Generator X/R Ratio

5.5 Metering

5.5.1 Theory

Watts and vars can be measured with three elements, as presented in Figure 5.12. Basically, under balanced conditions, the three-phase MVA can be determined by measuring the MVA in one transformer and multiplying by 3. The three-phase MVA multiplied by the cosine of the power factor angle will yield the total MW, and the sine of the angle will provide the total MVAR. However, if a neutral conductor is not provided for load purposes, three-phase watts and vars can be measured accurately with only two elements.

Figure 5.13 illustrates the voltage and current connections for three-phase two-element metering. The connection is not phase rotation sensitive and requires two phase currents that are 120 degrees apart with the voltage or potentials for each element lying inside their associated current by 30 degrees. Blondel's theorem indicates that two watt elements can accurately measure any level of unbalanced phase load and power factor as long as there is no neutral current flowing. For example, assuming a three-phase balanced load of 10 amps and 100 volts at unity power factor, each element

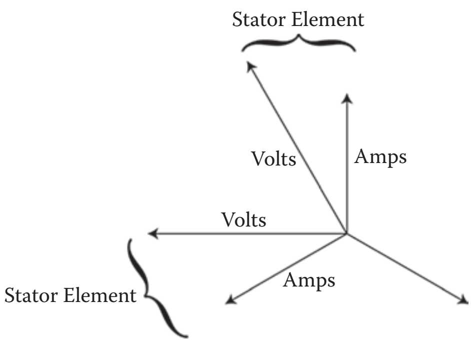


$MVA = (E_A \times I_A) + (E_B \times I_B) + (E_C \times I_C)$

$Watts = MVA \times Cos\ (Angle)$

$Vars = MVA \times Sin\ (Angle)$

FIGURE 5.12
Three-Element Metering



Blondel's Theorem

$3\text{-}Phase\ Watts = E_l \times I_l \times \sqrt{3} \times Cos\theta$

$(E_l \times I_l \times 0.866) + (E_l \times I_l \times 0.866)$

FIGURE 5.13
Two-Element Metering

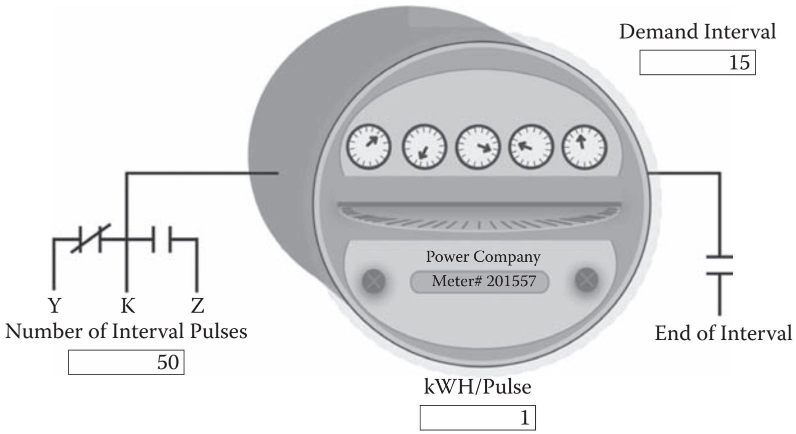
would measure 10 × 100 × .866 (cosine 30) or 866 watts. The total for both elements would be 866 plus 866 or 1732 watts (same as the standard power formula). If the power factor or load angle is changed from zero to 30 degrees lagging, the top element would measure 500 watts and the bottom 1000 watts or 1500 watts total (same as standard power formula).

5.5.2 Watt Demand

Watt demand is the maximum or peak watts consumed over a selected time interval. The peak value is stored until it is replaced with a higher peak from a different time interval or is reset to zero for the next revenue period (usually monthly). Most commonly, demand intervals of 15, 30, or 60 minutes are used for revenue metering applications. Normally, demands are corrected to a 60-minute or one-hour period. For example, to make a 15-minute measurement equivalent to a one-hour period, it would be multiplied by 4. At that point, watts and watt-hours would have the same value. In other words, if a load of 100 watts were held constant for one hour, it would consume 100 watt hours. Customers with demand readings will usually have an extra utility demand charge above the kWh consumption charge for the peak demand measurement. The rationale for the demand charge is that the utility is required to size their equipment to carry the peak demand.

Figure 5.14 illustrates isolated contact pulses coming from a meter. One pulse is normally represented by a transition of the form C output contacts. The contact transitions are usually provided by isolated mercury wetted reed relays or electronic solid-state relays. The pulses could be used for driving a data acquisition system, load management equipment, or the plant DCS system. For revenue metering applications, the utility or metering engineer will provide the amount of kWh energy in one pulse or transition. If only one-half the output contacts (form A) are used, then a contact open is a pulse and a contact close is another pulse. Form C or three-wire pulses were designed for increased integrity. Normally, three-wire pulses are conditioned by a reset-set (RS) flip-flop logic that will not allow a pulse to register until one contact opens and the other contact closes. This prevents false registration from bouncing contacts and induced voltages. To condition form A contacts, a time delay of 20 to 30 milliseconds is usually provided. Revenue meters are typically equipped with end-of-interval contacts. They are normally provided in a form A contact configuration (single contact) and momentarily close at the start of each new demand interval. If the utility furnishes customers with the end-of-interval contact, the customer can tell precisely when the demand period starts and ends and synchronize their load management systems with the revenue meter.

As can be seen from the example calculations in Figure 5.14, if (50) 1 kWh pulses were received in 15 minutes, each pulse would have a demand constant of 4 and the calculated demand for the 15-minute period would be 200 kW.



$$\textit{Pulse kWC} = (60/\textit{Interval}) \times (\textit{kWH/Pulse}) \quad \boxed{4}$$

$$\textit{kW Demand} = \textit{kWC} \times (\textit{Interval Pulses}) \quad \boxed{200}$$

Notes:
Each transition of the KYZ output contacts equals one pulse. If only K-Z or K-Y is used, a contact open is a pulse and a contact close is another pulse.

FIGURE 5.14
Watt Demand

5.5.3 Watts

Figure 5.15 covers a procedure for determining real time watts from an induction disk watt-hour meter if the instrument transformer ratios, the secondary kh value, and the number of revolutions over a specified number of seconds are known. This, of course, assumes that the load is held constant over the measuring period. The secondary Kh is the amount of secondary watt-hours for one revolution of the meter disk. Modern digital watt-hour meters will normally display the instantaneous watt and var measurements.

5.6 Motors

5.6.1 Acceptance DC Hi-Pot

Insulation systems for medium voltage motor stators are normally DC overvoltage or hi-pot tested at acceptance values to fix after shipment, new installation, or repair warranty responsibilities and to prove that the apparatus is fit for service. DC is used instead of AC because of the amount of

CT Ratio–1	120
PT Ratio–1	100
Secondary k_h	5
Revolutions	2
Seconds	10

$$Watts = \frac{k_h \times Revs \times CT \times PT \times 3600}{Seconds} \quad 43200000$$

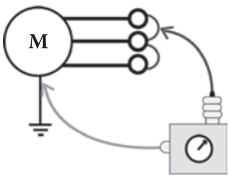
$$kW = Watts/1000 \quad 43200$$

$$MW = Watts/1{,}000{,}000 \quad 43.2$$

Notes:
Allows the user to extrapolate real-time watts from an induction disk watt-hour meter. Assumes that the load is constant over the measuring period.

FIGURE 5.15
Watts

Ph-Ph Rated kV
4



$$Factory\ Test\ kV = ((2 \times Rated)+1) \times 1.7 \quad 15.3$$

$$Acceptance\ Test\ kV = Factory \times 0.85 \quad 13.005$$

Notes:
Complies with NEMA Standard MG 1-3.01k.

FIGURE 5.16
Motor Acceptance DC Overvoltage Testing

vars needed to support the insulation capacitance. The relatively high AC var load in comparison to DC necessitates the need for a higher capacity AC hi-pot test set that is relatively expensive and more difficult to transport to the site. Normally, all three phases are jumpered together to reduce the possibility of damaging transient voltages if the test is suddenly interrupted.

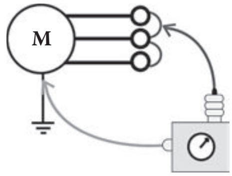
Figure 5.16 provides recommendations on DC acceptance test kV levels. NEMA standard MG 1-3.01K addresses this matter, as shown in the notes section of the figure. As with generators, the AC factory test is performed at twice rated phase-to-phase kV plus 1 kV. Acceptance tests are normally performed at 85% of the factory value. The AC value is then multiplied by 1.7 to convert it to an equivalent DC magnitude.

Rated kV

4

% Rated kV

125



$$DC\ Hi\text{-}Pot\ kV = Rated \times \frac{\%Rated}{100} \times 1.7 \quad \boxed{8.5}$$

Notes:
125% to 150% complies with IEEE Standards 432-1976 for suitability for continued service tests.

FIGURE 5.17
Motor Routine DC Overvoltage Testing

5.6.2 Routine DC Hi-Pot

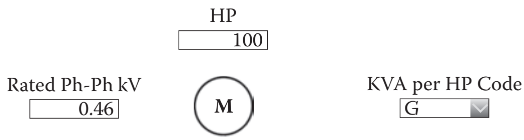
Insulation systems for medium voltage motor stators are normally DC overvoltage or hi-pot tested during unit overhauls to provide a measure of confidence that the insulation system will in all likelihood perform its intended job until the next overhaul. The AC level recommended by IEEE Standard 432-1976 for the routine AC overvoltage testing of motors is 125% to 150% of the rated phase-to-phase voltage.

Figure 5.17 presents recommendations on DC routine test kV levels for motors. There is also an industry consensus that a test level of 125% to 150% of the phase-to-phase voltage is high enough to predict a future life. As with generators, a value of 125% of the rated phase-to-phase voltage multiplied by 1.7 for an equivalent DC magnitude is suggested because it is more defendable in case the insulation system fails to carry the voltage. A failure in the stator slot areas normally requires a partial or full rewind. If you elect not to overvoltage test during a major outage and the insulation fails shortly after returning the unit to service, you may not be in a defendable position.

From the plant manager's perspective, the motor was working fine before the outage, and an overvoltage test failure may be costly to repair, extend the outage, and negatively impact the plant budget. If plant managers do not overvoltage test the stator insulation system during a major outage and the insulation fails shortly after return to service, plant managers are not in a defendable position. If plant managers hi-pot at the 125% minimum routine value, they can take the position that it is lucky that they found the problem during the outage as they were only testing at the minimum value.

5.6.3 Locked Rotor Amps

Motors manufactured according to NEMA standards normally have a starting kVA per HP code letter stamped on the nameplate that is used to determine locked rotor amps. Tables that are provided in NEMA MG-1-1978



$$Max.\ Locked\ Rotor\ Amps = \frac{Max.\ Code \times HP}{Rated\ kV\sqrt{3}} \quad \boxed{789.464}$$

$$Impedance = \frac{Rated\ kV \times 10^3}{\sqrt{3} \times LRA} \quad \boxed{0.336}$$

Notes:
Locked rotor indicating codes provided are in agreement with NEMA MG-1-1978.

FIGURE 5.18
Motor Locked Rotor Amps

indicate a range of kVA per HP factors for each code letter. Figure 5.18 provides a procedure for calculating locked rotor amps if the code letter is known. In the interest of providing some margin in the calculation, the maximum kVA per HP factor is normally assumed.

5.6.4 Unbalanced Voltages

Motors are very sensitive to the unbalance of supply voltages. Even a 1% or 2% imbalance can cause overheating and shorten the life of the motor. The unbalance causes negative sequence current flow in the rotor, at twice the supply frequency. The negative phase sequence currents increase rotor and stator winding losses and cause a small component of negative torque. Unbalanced resistances and reactance along current paths in the various connections, external and internal to the motor, may also cause a voltage unbalance, with the potential of reducing the expected life of the motor. Figure 5.19 demonstrates a NEMA motor standard procedure for calculating the percent voltage unbalance and determining a derating factor for the motor. The procedure is particularly useful where the angles are not known and a negative phase sequence calculation would be difficult to perform.

The generally recognized upper limit for running a motor with unbalanced voltages is 5%. As the figure shows, the average voltage is 484, the maximum deviation from average is 24, and the voltage unbalance is 5%. The voltage unbalance derating factors are shown in the figure in 1% steps to 5%. The respective horsepower derating factors are 98%, 96%, 92%, 85%, and 76%.

5.6.5 X/R Ratio

For more refined motor studies, the X/R ratio needs to be determined. Figure 5.20 shows the X/R ratio for a typical 100 HP, 1755 RPM, motor at

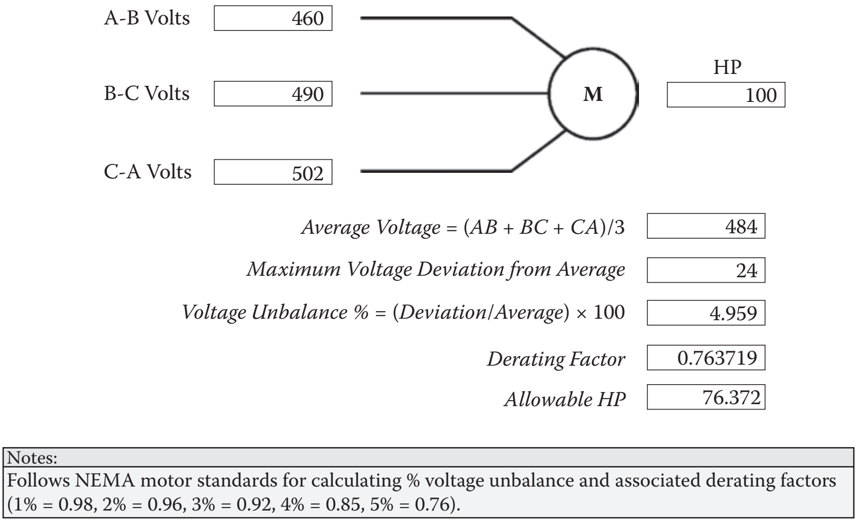


FIGURE 5.19
Motor HP Derating for Supply Voltage Unbalances

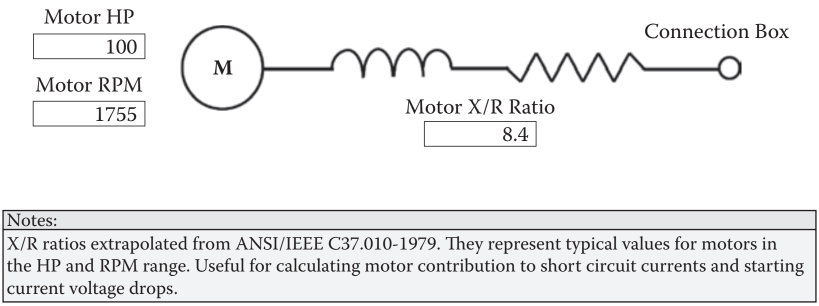


FIGURE 5.20
Motor X/R Ratio

locked rotor amps. ANSI/IEEE Standard C37.010-1979 presents curves for estimating typical X/R ratios based on motor HP and RPM values. The X/R ratio is useful for calculating motor starting current voltage drops and for determining motor short circuit contribution angles.

5.6.6 Switching Transients

During the late 1980s, the Electrical Power Research Institute (EPRI) contracted with Ontario Hydro and Rensselaer Polytechnic to complete a study on medium voltage motor turn to turn insulation and possible damage from switching transients. The study was particularly thorough and considered surge capacitors, cable shielding, location of the feeder breaker in the line-up,

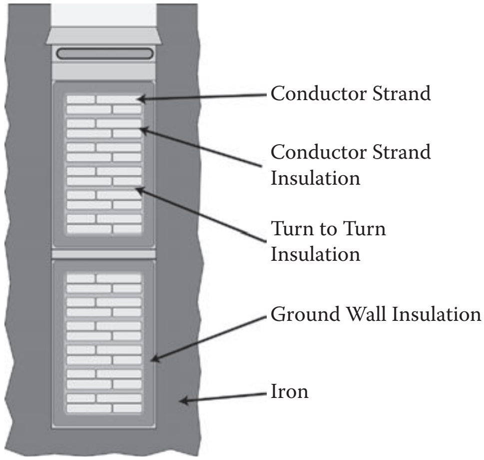


FIGURE 5.21
Motor Form Wound Coils

power supply grounding impedance, horsepower, nominal voltage, length of cable, type of cable, type of circuit breaker, and number of bus loads for medium voltage motors. With the exception of power supply grounding circuit breaker type and location, all of the foregoing parameters impacted either the maximum per-unit transient magnitude or the rise time or both.

As shown in Figure 5.21, six turns are illustrated in both the top and the bottom bars. The turn to turn insulation capability of form wound medium voltage coils is much lower than the ground wall insulation because the operating voltage is distributed across several turns and is generally in the range of 10 to 100 volts. However, circuit breaker switching can produce high frequency high voltage transients that can be damaging to the turn to turn insulation. Figure 5.22 shows a simplified model of a stator winding with distributed capacitance. Because the XL increases with high frequencies and the XC decreases, the capacitance shunts the transient voltage to ground across the first few turns, which dramatically increases the turn to turn voltage magnitudes. Generally, surge capacitors do not decrease the magnitude but increase the rise time, which lowers the frequency and distributes the transient voltage across a greater number of turns, thereby reducing the turn to turn voltage. Most generating stations are reluctant to apply surge capacitors because they represent a stored energy device, have a higher failure rate, are not compatible with alarm-only ground schemes, and hamper efforts to test motor insulation systems. Depending on the parameters discussed in the preceding paragraph, the maximum transients were both measured and simulated during circuit breaker second-pole closing and not interruption. The highest measured switching transient was 4.6 per unit, and the simulated transients were typically around 5.1 per unit with rise times of

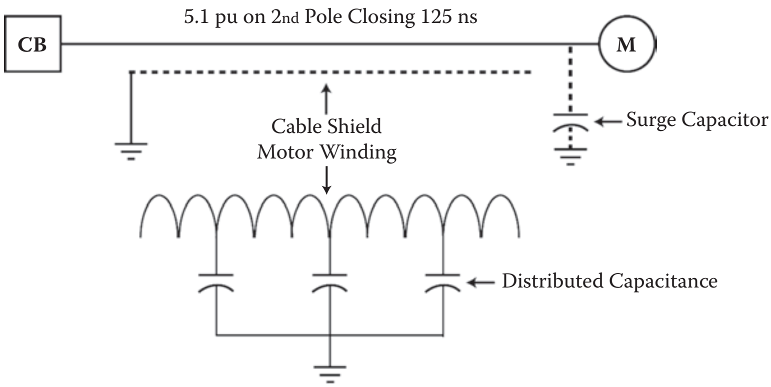


FIGURE 5.22
Motor Switching Transients

125 nanoseconds depending on the selected parameters. The per-unit values are in relationship to nominal phase-to-neutral voltages. The greatest impact for reducing transient magnitudes was cable shield grounding. Standard practice is to ground the shield at the switchgear end only. However, the EPRI study disclosed that grounding the shield at the motor end only without the surge capacitors, as shown in Figure 5.22, would reduce 5.1 transients to 2.3 per unit with an 85 nanosecond rise time. Intuitively, the 125 nanosecond rise time probably limits the voltage to the first few turns anyway and reducing the rise time further probably does not have that much of an impact, but reducing the magnitude by more than 50% should have a much greater impact depending on circuit details.

5.6.7 Reliability

Also during the 1980s, EPRI contracted with General Electric to complete a study on motor failure rates and mechanisms. The study focused on generating station switchgear fed motors, 100 HP and larger. Altogether, they looked at 56 electric utilities and 132 generating units and discovered there was a 12 to 1 ratio when plant failure rates were compared. The worst locations had 9.3% failures per year, and the better locations had 0.8% failures per year.

The motor failure mechanisms identified in the report by percentage were the following:

- Bearing related (41%)
- Stator related (37%)
- Rotor related (10%)
- Other (12%)

Although environmental factors differ from site to site, there are a number of opportunities to improve the life of motors, reduce failure damage, and improve operating productivity at any location. Many of these have been covered in this and preceding chapters, and good operating and maintenance practices remain to be discussed in Chapters 6 and 7. Opportunities to extend motor life are listed here, along with the chapter in which they are discussed:

- Optimizing operating voltages—Chapter 2
- Motor overcurrent protection—Chapter 3
- Ground protection—Chapter 3
- Arcing ground transient voltage mitigation—Chapter 3
- Bus transfer schemes—Chapter 3
- Insulation testing—Chapters 5 and 7
- Motor switching transient mitigation—Chapter 5
- Operating practices—Chapter 6
- Maintenance practices—Chapter 7

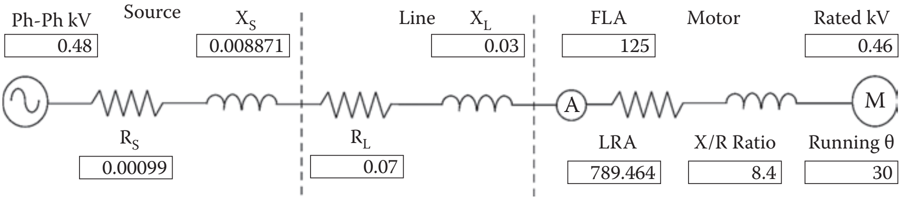
5.6.8 Voltage Drop

Figure 5.23 illustrates a procedure for calculating motor starting and running voltage drops. First, the source R and X and cable R and X values are determined. Then, the motor R and X for starting and for running conditions are determined. Finally, the total starting and running amps are calculated by dividing the phase-to-neutral voltage by the total circuit starting and running impedances, respectively. The phase-to-neutral voltages at the motor terminals for starting and running operations are determined by multiplying the calculated amps for each operational mode by the calculated motor impedances, respectively. The phase-to-phase voltages are then determined by multiplying the phase-to-neutral voltages by the square root of 3 or 1.732.

5.7 Transformers

5.7.1 Current Transformer Burden

When protective relays or other devices are added to protection circuits, care must be taken to ensure that the external secondary circuit impedance or burden does not impede the capability of the current transformer (CT) to accurately reproduce the primary current for protective relay operation. Figure 5.24 provides a procedure for calculating the maximum burden or



$$\textit{Locked Rotor } (Z_M) = \frac{\textit{Rated kV} \times 10^3}{\sqrt{3}\ \textit{LRA}}$$

$$\textit{Locked Rotor } \theta = \arctan\ (\textit{X/R Ratio})$$

$$R_M = Z_M Cos\theta$$

$$X_M = Z_M Sin\theta$$

$$Z_T = \sqrt{(R_S + R_L + R_M)^2 + (X_S + X_L + X_M)^2}$$

$$\textit{Source Phase–Neutral Volts } (E_N) = \frac{\textit{Ph-Ph kV} \times 10^3}{\sqrt{3}}$$

$$Z_R = \frac{\textit{Rated kV} \times 10^3}{\sqrt{3}\ FLA}$$

$$R_R = Z_R Cos\ (Run\ \theta)$$

$$X_R = Z_R Sin\ (Run\ \theta)$$

$$Z_{RT} = \sqrt{(R_S + R_L + R_R)^2 + (X_S + X_L + X_R)^2}$$

$$\textit{Load Amps } (I_L) = E_N / Z_{RT}$$

$$\textit{Inrush Amps } (I) = \frac{E_N}{Z_T} \qquad \boxed{712.377}$$

$$\textit{Acceleration kV} = \frac{I \times Z_M \times \sqrt{3}}{1000} \qquad \boxed{0.415083}$$

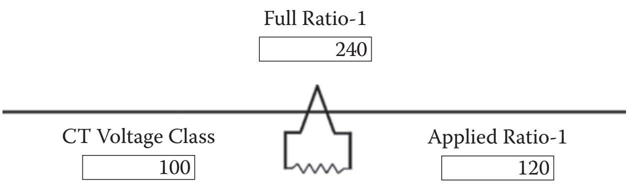
$$\%\ \textit{Acceleration kV} = \frac{Acc.kV}{\textit{Rated kV}} \times 100 \qquad \boxed{90.235}$$

$$\textit{Running kV} = \frac{I_L \times Z_R \times \sqrt{3}}{1000} \qquad \boxed{0.46239}$$

$$\%\ \textit{Running kV} = \frac{\textit{Run kV}}{\textit{Rated kV}} \times 100 \qquad \boxed{100.52}$$

Notes:
Typical Mid-Range X/R Ratios Are:
50 HP = 5.0
125 HP = 10.0
500 HP = 20.0
1500 HP = 30.0
5000 HP = 40.0

FIGURE 5.23
Motor Voltage Drop



$$N = \frac{\textit{Applied Ratio}}{\textit{Full Ratio}}$$

$$\textit{Maximum External Sec. Ohms} = \frac{N\,(\textit{Voltage Class})}{100} \qquad \boxed{0.5}$$

Notes:
See ANSI C57.13 for additional information.

FIGURE 5.24
Current Transformer Burden

ohms for relay class current transformers that are built to ANSI standards. As the figure shows, a 1200/5 or 240/1, 100-volt class, current transformer with an applied ratio of 120/1 can operate properly from 0 to 0.5 ohms. If the full winding was utilized, it could operate properly with up to 1.0 ohm in the external secondary circuit. To be more specific, for the relay class CT shown in Figure 5.24, the standards indicate that the error should not exceed 10% at 20 times rated current (100 amps secondary) with an external secondary circuit burden of 0.5 ohms or less at 50% power factor. Accordingly, the voltage class can be approximated as the point where the exciting current equals 10 amps during a CT saturation test. Exciting current above that point would cause the error to exceed 10%.

5.7.2 Power Transformer Losses

Power transformers can be visualized or represented as having equivalent parallel and series legs as illustrated in Figure 5.25. The parallel leg consists of a resistor and inductor in parallel that accounts for the no load watt loss and var consumption, and the series leg has a resistor and inductor in series that accounts for the full load watt loss and var consumption.

The no load watt losses are commonly called *iron losses* because the majority are associated with hysteresis and eddy currents losses in transformer core iron laminations. The hysteresis loss in AC electrical apparatus cores normally predominates and usually accounts for roughly two-thirds of the total no load watt loss. Although it can be reduced by adding silicon to the alloy to reduce the realignment or flip energy, carbon steel generally provides a better magnetic path. The magnetic path can also be improved by using grain-orientated steel, which also reduces the hysteresis loss. The remaining no load losses (roughly one-third) are reduced by laminating the iron into sheets in the direction of the magnetic flux to impede the flow of eddy currents.

The full load watt losses are commonly referred to as *copper losses* because the majority are caused by resistance in the primary and secondary windings. However, eddy currents that flow in the tank and supporting structures

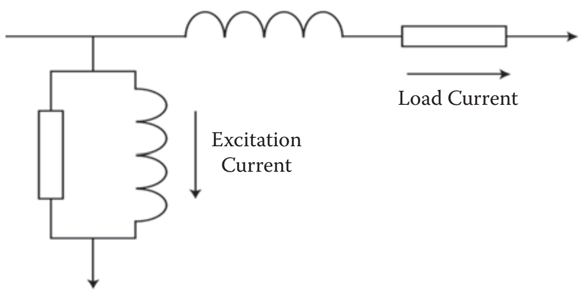
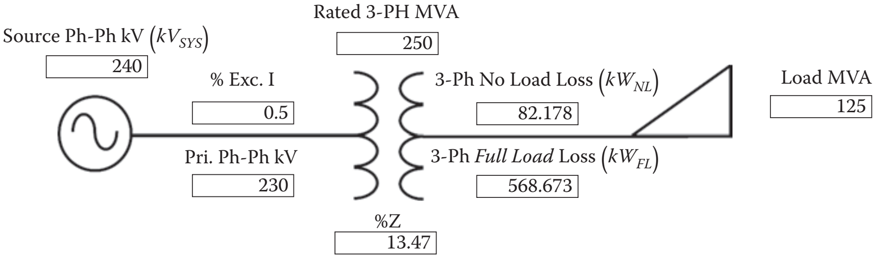


FIGURE 5.25
Transformer Loss Model



$$\textit{Rated FL Line Amps } (I) = \frac{Xfmr\ MVA \times 10^3}{\sqrt{3}\, kV_{PRI}}$$

$$\textit{No Load } (Z_{NL}) = \frac{kV_{PRI} \times 10^3}{\left(\left(\%\, Exc/100\right) \times I\right) \times \sqrt{3}}$$

$$\textit{Equivalent No Load } (R_{NL}) = \frac{\left(\left(kV_{PRI}/\sqrt{3}\right) \times 10^3\right)^2}{kW_{NL} \times 10^3} \times 3$$

$$\textit{Actual No Load Loss } (kW_{NL}) = \left(\frac{\left(\left(kV_{SYS}/\sqrt{3}\right) \times 10^3\right)^2}{R_{NL}} \times 3\right) \times 10^{-3} \quad \boxed{89.479}$$

$$\textit{Actual No Load } KVAR_{NL} = \left(\frac{\left(\left(kV_{SYS}/\sqrt{3}\right) \times 10^3\right)^2}{X_{NL}} \times 3\right) \times 10^{-3} \quad \boxed{1358.114}$$

$$Y = \frac{1}{Z_{NL}}$$

$$G = \frac{1}{R_{NL}}$$

$$B = \sqrt{Y^2 - G^2}$$

$$X_{NL} = \frac{1}{B}$$

$$\textit{Equivalent Full Load Loss } (R_{FL}) = \frac{kW_{FL} \times 10^3}{3I^2}$$

$$\textit{Actual Load Amps } (I_L) = \frac{Load\ MVA \times 10^3}{\sqrt{3}\, kV_{SYS}}$$

$$Z_{XFMR} = \frac{\%Z}{100} \times \frac{kV_{SYS}^2}{MVA_{XFMR}}$$

$$X_{FL} = \sqrt{Z_{XFMR}^2 - R_{FL}^2}$$

$$\textit{Actual Load Loss } (kW_L) = I_L^2 \times R_{FL} \times 3 \times 10^{-3} \quad \boxed{130.568}$$

$$\textit{Actual Load } KVAR_L = I_L^2 \times X_{FL} \times 3 \times 10^{-3} \quad \boxed{8417.74}$$

$$\textit{Total } KVAR_S = KVAR_{NL} + KVAR_L \quad \boxed{9775.85}$$

$$\textit{Total } kW = kW_{NL} + kW_L \quad \boxed{220.05}$$

Notes:
Useful for determining the cost of keeping a transformer energized and for assessing transformer watt and var consumption for balanced load flows on the secondary side. %Z should be corrected for applied taps and voltage.

FIGURE 5.26
Transformer Losses

cause an additional amount of full load watt losses. These are commonly called *stray losses* and are usually around 10% of the copper losses. Sometimes the term *copper loss* refers to both copper and stray losses. Another term, *impedance loss,* is sometimes used to indicate the total copper plus stray loss.

Figure 5.26 covers a procedure for determining three-phase transformer losses at different loads and system voltages if the no load and full load losses are known. The procedure can be used to determine watt and var deliveries on the secondary side for revenue metering applications or to perform economic evaluations of transformer losses.

Basically, to determine the no load watt loss and var consumption, first calculate the no load impedance per phase from the exciting current. Then derive the equivalent no load phase resistance that is required to produce the no load watt loss. Then determine the amount of parallel inductance by backing out the equivalent resistance from the calculated no load impedance using the conductance, susceptance, and admittance parallel impedance method. Now the actual no load watt loss and var consumption at the actual applied voltage can easily be determined. The per-phase values can be calculated by squaring the applied phase-to-neutral voltage and dividing by the equivalent resistance and then inductive ohms, respectively. Multiplying these values by 3 will yield the three-phase no load watt loss and var consumption, respectively.

To determine the actual load watt loss and var consumption, first calculate the rated full load amps. Then, divide the full load watt losses by 3 times the rated amps squared to determine the equivalent per phase series resistance. Correct the transformer %Z for applied taps and voltages and convert from percent impedance to ohms. Then determine the amount of X in the series circuit by backing out the equivalent resistance from the impedance ohms. Now the actual load watt loss and var consumption can easily be determined. The per-phase values can be calculated by squaring the actual primary current and multiplying it by the phase resistance and the phase inductance ohms, respectively. Multiply these values by 3 to obtain the three-phase load watt loss and var consumption, respectively. The total watt loss will be the sum of the no load and load loss watts and the total var consumption will be the sum of the no load and load vars.

5.7.3 Power Transformer X/R Ratio

If a three-phase transformer's full load losses (copper + stray) are known, a more refined X/R ratio during three-phase short circuit conditions can be calculated. The copper loss is a direct result of the resistances in the primary and secondary windings. The stray losses are caused by eddy currents in the tank and support structure areas and usually account for around 10% of the total load losses. Figure 5.27 presents a procedure for determining the X/R ratio. First, the full load current and impedance on the primary side is calculated. Then, the per-phase resistance is determined by dividing the full load losses by 3 times the full load amps squared. And finally, the X component is determined by backing out the calculated R from the calculated Z.

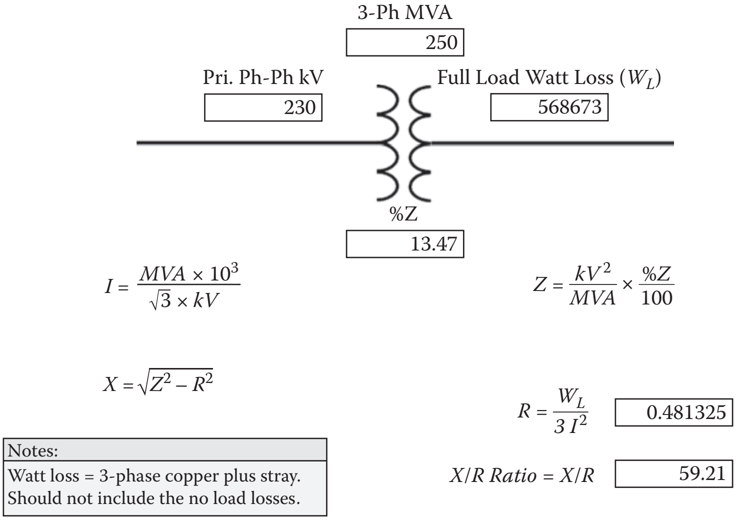


FIGURE 5.27
Transformer X/R Ratio

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6

Electrical Operating Guidelines

The guidelines are based on over 40 years of electrical operating experience in generating stations. They represent a procedural effort to improve the availability of generating stations and large industrial facilities and reduce hazards to plant personnel. Some of the text was developed following operating errors in stations and some to try to mitigate outages or equipment failures reported by the industry. However, there are a number of areas where the guidelines may need to be revised or upgraded by a generating station to meet their particular requirements. Some of these areas are presented below:

- The guidelines are general in nature and manufacturers' recommendations for their equipment have precedence over the guidelines.
- There may be government regulatory agencies whose recommendations have priority over the guidelines; for example, the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), Occupational Safety and Health Administration (OSHA), National Electrical Code (NEC), and so forth.
- The guidelines assume that the operators are well trained and qualified to perform the suggested tasks.
- The station may have site-specific environmental conditions that need to be accounted for in the guidelines.

The guidelines represent a good starting document. However, they should be treated as a work in progress that reflects the ever-changing government regulations and site-specific and industry experience in general.

6.1 Operation of Large Generators

6.1.1 Purpose

The purpose of this guideline is to ensure the continuing operational integrity of generators. Operating conditions that have forced units off-line or have damaged or shortened the life of turbine/generator components in the past are highlighted in the guideline to prevent recurrences in the future.

6.1.2 Startup Operation

In addition to monitoring the various generator support systems for cooling and lubrication, electrical parameters, temperatures, and vibration, inattention to the following areas has caused problems in the past:

- At no time should excitation interlocks or protective relay functions be bypassed or disabled for the purpose of energizing a generator's direct current (DC) field winding.
- For generators requiring field prewarming, the manufacturer instructions and established procedures should be followed relative to the allowable field currents.
- A generator field should not be applied or maintained at turbine speeds above or below that recommended by the manufacturer. On cross-compound units where a field is applied at low speeds or while on turning gear, extreme caution must be exercised. Should either or both shafts come to a stop, the field current should immediately be removed to prevent overheating damage to the collector or slip rings.
- After the field breaker is closed, the generator field indications should be closely monitored. If a rapid abnormal increase occurs in field current, terminal voltage, or both, immediately open the field breaker and inspect the related equipment for proper working condition before reestablishing a field.
- During off-line conditions, at no time should the field current be greater than 105% of that normally required to obtain rated terminal voltage at rated speed in an unloaded condition. Typically, turbogenerators are designed to withstand a full load field with no load on the machine for only 12 seconds; after that, severe damage can occur to the stator core iron laminations.
- When synchronizing a generator to the system, the synchroscope should be rotating less than one revolution every 20 seconds. Phase angle differences should be minimized and no more than 5 degrees out of phase when the circuit breaker contacts close. Phase angle differences as little as 12 degrees can develop shaft torques as high as 150% of full load and damage shaft couplings and other turbine and generator components. Manufacturers usually recommend limiting maximum phase angle differences to 10 degrees. It is also desirable that incoming and running voltages are matched as closely as possible to minimize reactive power flow to or from the electrical system. In general, the voltages should be matched within 2% at the time of synchronization. The speed of the turbine should be slightly greater than synchronous speed prior to breaker closure to help ensure that the unit will not be in a motoring condition following

connection to the electrical system, and the generator voltage should be slightly higher to ensure var flow into the system instead of into the generator.

NOTE: Under no circumstances should operators allow a unit to be synchronized using the sync-check relay as the breaker-closing device (i.e., holding a circuit breaker control switch in the closed position and allowing the sync-check relay to close the breaker). Some sync-check relays can fail in a "closed" state, allowing the circuit breaker to be closed at any time.

6.1.3 Shutdown Operation

Normally, units are removed from service through operator initiation of distributed control system (DCS) commands or turbine trip buttons that shut down the prime mover. Closure of steam or fuel valves will then initiate antimotoring or reverse power control circuits that isolate the unit electrically by opening the generator circuit breakers, field breakers, and, depending on the design, unit auxiliary transformer (UAT) low side breakers. If limit switch circuitry or antimotoring/reverse power relays fail to operate properly, the unit may stay electrically connected to the system in a motoring condition. If excitation is maintained, this condition is not harmful to the generator. However, the turbine blades may overheat from windage. On steam units, the low pressure turbine blades are impacted the most, with typical withstands of 10 minutes before damage. However, the unit can be safely removed from service with the following operating steps:

- Verify that there is no steam flow or fuel flow in the case of combustion turbine units to ensure that the unit will not overspeed when the generator circuit breaker(s) are opened.
- Transfer the unit auxiliary power to the alternate source if opening the unit breakers will de-energize the UAT.
- Reduce or adjust the generator's output voltage (voltage regulator) until the field current is at the no load value, and transfer from automatic voltage regulator mode to the manual mode of operation.
- Open the generator circuit breaker(s).
- Open the generator field breaker.

6.1.4 On-Line Operation

When the generator is on-line, particular attention should be paid to the following:

- Generators should be operated within their capability curves, which limit loading and field current (as related to var input and output) at various levels of hydrogen pressure. Operation beyond these limits will result in overheating and loss of life of various generator components.

- The generator stator and rotor operating temperatures should be closely monitored.
- Proper water flow to the hydrogen or air coolers (as pertinent) must be maintained. *(As little as 10% of rated load can severely overheat a hydrogen-cooled generator that does not have water flow to the hydrogen coolers.)*
- If conditions require operation with the voltage regulator on manual, the unit should be off automatic generator control (AGC) with the turbine at blocked load. Operators should keep a close watch on var output to ensure that the unit remains in a boost mode (supplying vars to the system). With the automatic voltage regulator out-of-service, changes in system voltages can cause the unit to buck vars and trip on loss-of-excitation.
- Units that are designed with stator ground voltmeters or protective relays that display stator ground voltages should be monitored by operations periodically. A healthy generator will produce a few volts of third harmonic voltage during normal operation. The exact level is generator-specific and depends on the amount of real and reactive power that the generator is carrying. The absence of voltage when the generator is on-line indicates that either the stator ground scheme has an open circuit (safety switch open, grounding transformer racked out, or open conductor) or the generator has a stator ground near the neutral end where the ground protection does not have the sensitivity to detect the problem. Loss of the third harmonic voltage when the unit is on-line should be quickly investigated and resolved to ensure that the generator is properly protected and to minimize damage in the case of an actual ground condition. Some units are equipped with third harmonic stator ground relays that will automatically alarm or trip the unit off-line if the normal third harmonic voltage decays.

  NOTE: Operating with a significantly reduced field (buck vars) can lower the third harmonic levels to the extent that it may actuate the third harmonic tripping relay.

6.1.5 System Separation

If, during system trouble, the unit is separated from the system, close attention to the field current/generator terminal voltage must be maintained, particularly when the unit is not operating at rated speed, to prevent catastrophic volts per Hertz (volts/Hz) damage to the generator stator core iron. Reduction in speed can result in overexcitation (volts/Hz) as the automatic voltage regulator attempts to maintain rated voltage. At no time should the field current of an unloaded machine exceed 105% of that required to produce rated terminal voltage, at rated speed, with no load.

In general, generating units should not try to pick up blocks of load that exceed 10% of the machine rating. Attempts to do so may cause a collapse of the generator voltage and the loss of the unit.

Many generating units are not equipped with out-of-step relaying. If the watt/var outputs are swinging wildly, the unit may have lost synchronization with the electrical system. Loss-of-excitation relays may or may not operate for this condition. After quickly eliminating automatic voltage regulator, power system stabilizer (if equipped), process control, and governor instability as problem areas, quickly remove the unit from service to reduce the possibility of damage to the turbine/generator system.

6.1.6 Field Grounds

An internal generator field ground could be caused by high temperature electrical arcing, insulation damage, elongated end turn conductors, brush-rigging problems, or other anomalies in the generator field. If a second ground occurs inside or outside the field in the opposite polarity, DC short circuit currents will flow that can damage the rotor forging, retaining rings, wedges, collector rings, journals, and bearings. For that reason, manufacturers normally recommend automatic tripping for field ground events. Generating stations usually elect not to trip automatically because experience has shown that the ground is usually located in the peripheral excitation equipment and not in the generator rotor and, consequently, risk or exposure to the rotor is quite low. However, if the field ground is coincident with a notable step change in either generator bearing vibration or field temperature, then the probability of the ground being in the rotor is quite high and the unit should be quickly removed from service to mitigate the possibility of rotor damage.

Each station should have detailed operating instructions that address locating and isolating field grounds for each type of excitation system. Timely and thorough investigations should be performed to identify and isolate the source of the field ground. Considering the numerous components associated with the excitation system, it is possible that the ground is outside the generator rotor and can be corrected without removing the unit from service. The following investigation steps are recommended to try and isolate the location of field grounds:

- Operators momentarily transfer from automatic voltage regulation to manual.
- Operators pull fuses to noncritical loads, that is, monitoring transducers, DCS inputs, and field temperature recorders.

- Technicians verify that the field ground detector relay is operating properly.
- Technicians/electricians inspect brush rigging and the excitation system.
- Technicians lift wires (where possible with the unit running) to further isolate excitation system components.

If the ground cannot be isolated, the unit should be quickly removed from service for further investigation.

6.1.7 Voltage Regulators

Automatic voltage regulator instability is evident when the regulator output meter and the unit var meter swing between buck and boost. The swings may increase in magnitude. If this occurs, the voltage regulator should be transferred to the manual mode of operation. Electrical system disturbances are typically indicated by large initial voltage regulator output and unit var swings, which dampen out in a few seconds.

When transferring between automatic voltage regulator control and manual operation and visa versa, verify that the regulator output is nulled or at zero differential. Improper transfers can expose the generator to overexcitation (volts/Hz) or underexcitation (loss-of-excitation) and trip the unit off-line.

6.1.8 Moisture Intrusion

Even small amounts of moisture inside generators can result in reduced dielectric capability, stress corrosion pitting of retaining rings, and lead carbonate production and plating of the machine surfaces. The following recommendations should be adhered to in order to maintain generators in a dry condition:

- The backup seal oil supply from the bearing lube oil system has a higher moisture content and should only be used in emergency situations.
- Hydrogen dryers must be maintained properly.
- Hydrogen dryer desiccant should be monitored and replaced or regenerated as required.
- Hydrogen cooler and inner cooled stator coil water leaks should be reported and repaired in a timely manner.
- Moisture monitors and detectors should be routinely checked for proper operation and calibration.
- Space heaters, when installed, should be verified as working when the unit is off-line.

Generators equipped with nonmagnetic *18-5* retaining-rings must be maintained in a dry condition to reduce the possibility of stress-corrosion pitting and cracking damage to the rings. These units should be taken off-line at the first indications of moisture intrusion (maximum dew point of 30 degrees F) and any required repairs completed before returning the unit to service.

6.1.9 Routine Operator Inspections

To maintain the operating integrity of generators, the following checks should be routinely performed by operations personnel when making their daily inspection rounds:

- Check hydrogen purity levels (where applicable), and adjust gas flow to the purity monitor as required.
- Check that the seal oil system is operating properly. Verify that the proper pressure differential between the seal oil and hydrogen gas systems is maintained (where applicable).
- Check that the hydrogen dryers are in service (where applicable) and operating properly, and check that the desiccant is in good condition.
- Check the liquid detectors for accumulation of water or oil.
- Verify proper water flow to hydrogen or stator coolers (where applicable).
- On generators equipped with water-cooled stator coils, verify proper flow, conductivity, and differential pressure between the water and the hydrogen gas systems.
- Check the stator, gas, and field temperatures.
- Check the bearing vibration levels.
- Check the generator stator ground scheme for proper residual or third harmonic voltages.
- Check the brush rigging (where applicable) for broken, vibrating, and arcing brushes.

NOTE: It is recommended that at least once daily the brush rigging be inspected through available windows, without opening doors or covers while the machine is on-line.

- When the rotor is stopped or on turning gear, the brush-rigging area should be checked periodically for hydrogen leakage (where applicable). Hydrogen gas can leak through the bore conductors and accumulate in the brush-rigging areas when the unit is off-line.

- Check the shaft grounding brushes or braids to verify physical integrity. In those units, where the grounding brushes or braids are not visually accessible, please refer to maintenance guideline for periodic maintenance.
- Verify that the field winding ground fault detection system is operational.

Anomalies found during the routine inspections should be monitored and work orders prepared to resolve problems noted.

6.1.10 Generator Protection

6.1.10.1 Differential (87)

Generator differential relays compare the secondary currents from current transformers (CTs) installed on the neutral end of the generator windings to current transformers installed on the output side of the generator or the output side of the generator circuit breaker. If an internal phase-to-phase or three-phase fault occurs between the neutral and output CTs, the current flows will not balance and the differential relay will instantaneously actuate to trip the unit off-line. In general, these relays will not be able to detect ground faults or shorted turns in the stator windings.

> **NOTE:** The unit should not be re-energized following a generator differential trip until the cause of the relay operation can be determined and resolved by engineers or technicians.

6.1.10.2 Stator Ground (64) or (59G)

Generator stator ground schemes protect the generator, isolated-phase buses, generator bus circuit breaker (if included), arrestors and surge capacitors (if included), and the primary windings of potential, auxiliary, and main step-up transformers from breakdowns in the insulation system to ground. Typically, the stator ground relays are set to operate in 1.0 second for a 100% ground fault condition. The relay senses voltage on the secondary side of the generator stator-grounding transformer, which is connected between the generator neutral and the station ground grid. Under normal operation, the relay will see a few volts of third harmonic (180 Hz for 60 Hz machines), due to the nonsymmetry and partial saturation of the stator core iron, and zero volts at normal system frequencies (60 Hz). The stator ground relays are usually desensitized at 180 Hz and are normally set to operate for a 5% ground at system frequencies.

Tripping schemes are available that will remove the unit from service on loss of third harmonic. At minimum, this voltage should be monitored to verify that the grounding scheme is healthy and there is no ground at the neutral end of the generator where a conventional relay does not have the sensitivity to detect grounds. In general, when a protective relay measures the third harmonic voltage, tripping is preferred for salient pole hydro machines, but alarm-only operation is preferred for cylindrical rotor machines because of the robust construction of the higher speed generators.

> **NOTE:** The unit should not be re-energized following a generator stator ground trip until the cause of the relay operation can be determined and resolved by station engineers or technicians.

6.1.10.3 Bus Ground Detectors (64B) or (59BG)

Units equipped with generator medium voltage circuit breakers require a second ground detector scheme to protect the generator circuit breaker, isolated phase buses on the transformer side of the circuit breaker, and the primary windings of potential, auxiliary, and main step-up transformers from ground fault conditions when the generator circuit breaker is open. This scheme normally uses a wye–broken delta connection with a voltage relay installed on the secondary side to sense ground conditions. Under normal conditions, when the unit is running, this scheme will detect a few volts of third harmonic and zero volts at running frequency. However, the scheme can become unstable under certain conditions (neutral instability or three-phase ferroresonance), causing a blown fuse(s) in the ground detecting transformers. A blown fuse may cause the ground detector relay to actuate. Also, coordination between the generator stator and bus ground detector schemes is difficult and, depending on the design, the station may not be able to quickly ascertain which side of the generator circuit breaker has the ground condition.

Preferred designs alarm only for bus ground detector schemes, or alarm when the generator circuit breaker is closed, and trip with a short time delay when the generator circuit breaker is open. This prevents the unit from tripping for blown fuse conditions and allows operators to quickly determine which side of the generator circuit breaker has the ground condition. With these designs, the generator stator ground relay will trip the unit for a ground on either side of the generator circuit breaker when the unit is on-line. If the ground is on the generator side of the circuit breaker, the ground will clear after tripping. If not, the bus ground detector will alarm or trip the unit main step-up transformer after generator tripping. For alarm-only schemes, the bus section should be immediately de-energized by operations through the appropriate switching to mitigate the possibility of the low-level ground fault current developing into a damaging high current double line to ground, phase-to-phase, or three-phase short circuit.

> **NOTE:** The main transformer should not be re-energized following a generator bus ground event until the cause of the relay operation can be determined and resolved by engineers or technicians.

6.1.10.4 Loss of Excitation (40)

Synchronous generators are not designed to be operated without DC excitation. Unlike induction machines, the rotating fields are not capable of continuously handling the circulating currents that can flow in the rotor forging, wedges, amortisseur windings, and retaining rings during underexcited or loss of field operation. Consequently, loss-of-excitation relays are normally included in the generator protection package to protect the rotor from damage during underexcitation operating conditions. Impedance-type relays are normally used to automatically trip the unit with a short time delay whenever the var flow into the machine is excessive. Limits in the automatic voltage regulator should be set to prevent loss-of-excitation relaying whenever the voltage regulator is in the automatic mode of operation.

> **NOTE:** The machine should not be re-synchronized to the system following a loss-of-excitation trip until an investigation has been completed to determine the cause of the relay operation.

However, considering the complexity of modern excitation systems, unexplained events are not that uncommon. Engineers or technicians should inspect the physical excitation system, verify calibration of the loss-of-excitation relays, check the DC resistance of the generator field windings, and review any available data acquisition monitoring that would verify the operating condition. The unit can then be started for test, and proper operation of the excitation system can be ascertained by operations before synchronizing the unit to the system.

6.1.10.5 Overexcitation (24)

Overexcitation (volts/Hz) relays are applied to protect the generator from excessive field current and overfluxing of the generator stator core iron. Typically, generators are designed to handle a full load field with no load on the machine for only 12 seconds before the stator iron laminations become overheated and damaged. Normally, the relays are set to trip the unit in 45 seconds at 110% volts/Hz and 2.0 seconds at 118% volts/Hz. The term *volts/Hz* is used to cover operation below normal system frequencies (60 Hz), where generators and transformers can no longer withstand rated voltages. Generators are continuously rated for operation at 105% voltage and transformers normally for continuous operation at 110% voltage. Consequently, the generators are usually the weak link, and safe operation for generators, in most cases, will automatically protect unit transformers that are connected to generator buses.

> **NOTE:** The unit should not be re-synchronized to the system following a volts/Hz trip until an investigation has been completed to determine the cause of the relay operation.

However, considering the complexity of modern excitation systems, unexplained events are not that uncommon. Engineers or technicians should inspect the physical excitation system, verify calibration of the volts/Hz relays, and review any available data acquisition monitoring that would verify the operating condition. The unit can then be started for test, and proper operation of the excitation system can be ascertained by operations before synchronizing the unit to the system.

6.1.10.6 Reverse Power (32)

Reverse power or antimotoring relays are often applied for control purposes and for protective relaying. In the control mode, they are typically used to automatically remove units from service during planned shutdowns and to ensure that prime movers have no output before isolating units electrically to prevent overspeed conditions. In the protection mode, they are used to protect turbine blades from windage overheating and sometimes to protect combustion turbine units from flameout conditions. The reverse power or antimotoring protective relays should have enough time delay before tripping to allow for synchronizing excursions (typically around 20 seconds). *Motoring* is not damaging to generators as long as proper excitation is maintained. In steam turbines, the low pressure turbine blades will overheat from windage. Typically, steam turbine blades can withstand motoring conditions for 10 minutes before damage. In hydro turbines, motoring may cause water cavitations. Combustion turbines also consume a fair amount of watts when in a motoring mode of operation.

> **NOTE:** Following a reverse power or antimotoring protection trip, operations should determine if the trip was caused by control instability by reviewing recorder or DCS trending of unit megawatt output. If control instability is evident, engineers or technicians should investigate and resolve the problem before re-synchronizing the unit. If control instability is not evident, engineers or technicians should check the calibration of the reverse power or antimotoring relay before returning the unit to service.

6.1.10.7 Negative Phase Sequence (46)

Unbalanced phase current flow in generator stators cause double-frequency reverse rotation negative-phase sequence currents to circulate in the rotor body that can damage the rotor forging, wedges, amortisseur windings, and retaining rings. Many generators designed according to ANSI (American National Standards Institute) standards are capable of continuously carrying 10% negative phase sequence current. Depending on the design of the generator (indirectly or directly cooled) generators with two phases at rated current and no current in the third phase may only be able to carry this unbalance for 30 seconds before damage occurs to the rotor components. Accordingly, negative phase sequence relays are necessary to protect generator rotors from thermal damage during all possible operating conditions, including phase-to-phase and phase-to-ground faults on the transmission system.

Some negative sequence overcurrent relays provide an alarm function with a pickup value set somewhere below the trip point. This alerts the unit operator to a negative sequence condition prior to a trip. If the negative sequence alarm is initiated, the operator should take the following actions:

- Notify the transmission dispatcher of the negative sequence condition and find out if there are any electrical problems on the transmission system. When a negative phase sequence alarm is activated, operators should also check the phase currents for balance. In addition to off-site causes for unbalance, open conductors, disconnect poles, or breaker poles at the site can cause the unbalanced conditions. If no abnormalities exist, notify the dispatcher that load will be reduced on the generator until the alarm clears.
- The generation should be taken off AGC, and load should be reduced until the alarm clears.
- Engineers or technicians should verify calibration of the negative phase sequence relay and review any data acquisition monitoring devices (protective relay digital storage or DCS trends) to verify that the unit operated with a significant current unbalance.

If the alarm is coincident with any electrical switching in the switchyard or within the plant, the switching should be reversed, and if the alarm clears, the apparatus in question should be investigated for proper operation.

NOTE: Following a negative phase sequence trip, the unit should not be returned to service until the cause is determined by engineers or technicians and resolved.

6.1.10.8 Backup Impedance (21) or Voltage Restraint Overcurrent (51V)

Backup impedance relays are normally provided to backup generator and transformer differential relays and to thermally protect generators from three-phase balanced short circuits that do not clear properly from other protective relays applied in the plant or in the electrical system or from upsets or system disturbances. Zone 1 backup protection will usually operate in around 0.1 seconds to back up the differentials, and zone 2 backup protection will operate in approximately 2.0 seconds at 150 percent of rating to thermally protect the machine. Although generators should not be operated outside of their capability curves, industry standards require a capability of 130% of rated stator current for 1 minute. Some units may be equipped with a voltage restraint or controlled overcurrent relay that basically performs the same job as the backup impedance relay.

> **NOTE:** Following a backup impedance or voltage restraint overcurrent relay trip, the unit should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.9 Out of Step (78)

Out-of-step relays are primarily applied to protect turbine/generators from slip frequency power swings that can mechanically resonate and cause cycle fatigue failures of turbine/generator components. Out-of-step events can be characterized by wildly swinging watt and var indications and are usually caused by close in electrical system faults that do not clear fast enough. When a close in electrical system fault occurs, the watt load on a generator is displaced by vars. This basically unloads the machine and it speeds up. If the system relays do not clear the fault quickly enough (typically around 6 to 20 cycles), the speed of the turbine/generator system will increase past the point of recovery and the unit will lose synchronism with the system. In this case, the unit will go in and out of phase and the output indications will swing wildly.

> **NOTE:** Following an out-of-step relay trip, the unit should not be returned to service until engineers or technicians investigate and resolve the problem.

The out-of-step event may have been caused by an electrical system fault that did not clear promptly because of faulty electrical system circuit breakers or protective relays. Operations should communicate with the system dispatcher to see if that is the case.

6.1.10.10 Overfrequency and Underfrequency (81)

Almost always, the overfrequency or underfrequency protection of the unit is there to protect the turbine before it protects the generator. Turbines tend to be more sensitive to off-frequency operation than the generator. Therefore, the overfrequency and underfrequency protective devices are, in general, set to protect the turbine. The damage done to turbine blading during off-frequency resonant operation is accumulative and dependent on the duration of the event.

Operators should be aware of the frequency limitation for their particular turbines and should not operate them outside of the manufacturers' recommended limits under any circumstances.

NOTE: If a unit trips by the operation of an overfrequency or underfrequency relay, the unit should not be returned to service until the system frequency stabilizes within acceptable limits.

6.1.10.11 Sync Check (25)

When synchronizing a generator to the system, the synchroscope should be rotating less than one revolution every 20 seconds. Phase angle differences should be minimized and ideally be no more than 5 degrees out of phase when the circuit breaker contacts close. Phase angle differences as little as 12 degrees can develop shaft torques as high as 150% of full load and damage shaft couplings and other turbine and generator components. Manufacturers usually recommend limiting phase angle differences to 10 degrees. It is also desirable that incoming and running voltages are matched as closely as possible to minimize reactive power flow to or from the electrical system. In general, the voltages should be matched within 2% at the time of synchronization with the generator a little higher to ensure var flow into the system. The speed of the turbine should be slightly greater than synchronous speed prior to breaker closure to help ensure that the unit will not be in a motoring condition following connection to the electrical system.

Slow breaker protection is now available in some of the newer technology relays. This function will operate breaker failure protection to isolate the generator if the breaker is slow in closing. A typical breaker control circuit seals in when the close signal is dispatched through the X/Y scheme and the close cannot be aborted directly. The breaker trip coil cannot be activated until the breaker actually closes; consequently, the only way to prevent an out-of-phase closure during a slow breaker closing event is to operate breaker failure tripping to trip open adjacent breakers to isolate the failed breaker.

NOTE: Following slow breaker tripping, the unit should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.12 Inadvertent Energization (50/27)

This scheme protects an off-line at-rest generator from an inadvertent closure of a unit breaker. The logic recognizes that the unit is off-line and will trip the unit breakers instantaneously if there is a sudden application of voltage and a corresponding high level of current. Generators are not designed to be started as induction motors, and severe generator damage can be expected if the event is long enough in duration.

NOTE: Following an inadvertent energization trip, the unit should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.13 Pole Flashover (50NF)

For designs that utilize the switchyard breakers for synchronizing, pole flashover logic will protect generators from damaging current flow if one pole or phase flashes over. In general, circuit breakers are at greater risk during synchronizing operations because the voltage across the poles can double during revolutions of the synchroscope. Basically, if the scheme detects current flow in the main step-up transformer neutral and if the logic indicates that the unit breakers are open, it will actuate breaker failure tripping to isolate the faulted breaker. During a pole flashover event, the generator may experience high levels of phase-to-phase current, which could severely damage the generator and the circuit breaker if allowed to continue.

> **NOTE:** Following pole flashover tripping, the breaker should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.14 Main and Auxiliary Transformer Differential (87)

Transformer differential relays compare the current magnitudes and associated phase angles on the primary side of the transformer to the currents on the secondary side. Under normal conditions, the primary and secondary currents should balance out after considering the winding ratios. If they are out of balance enough, an electrical fault is assumed and the protection will actuate instantaneously to remove the transformer from service.

> **NOTE:** Following a differential protection operation, the transformer should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.15 Feeder Differential (87)

Some designs utilize a separate differential scheme to protect the line from the unit main step-up transformer and/or reserve or startup auxiliary power transformer to the switchyard. If the line currents at each end are not in agreement, a fault is assumed and the protection will instantaneously actuate to remove the line from service.

> **NOTE:** Following a line differential protection operation, the line should not be re-energized until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.16 Overall Unit Differential (87)

In lieu of installing an extra feeder differential, most generating stations apply an overall or unit differential that compares the current flow in the generator neutral to the current flowing in the unit high voltage switchyard circuit breakers. Accordingly, the overall scheme will detect faults in the generator, isolated phase bus, main step-up transformers, unit line to the switchyard, and unit switchyard circuit breakers. If, after considering the main step-up transformer ratio, the currents are out of balance, the relay assumes a fault and will actuate instantaneously to trip the unit off-line.

> **NOTES:** Normal practice for switchyard ring bus or breaker and one-half configurations is to open unit disconnects after tripping and re-close the unit switchyard breakers to tie the buses together to improve the integrity of the switchyard. For this case, the unit differential relay scheme is still protecting switchyard bus sections even though the unit is off-line. Accordingly, anytime the unit breaker(s) are closed and energized, the unit differential protection must remain in-service. Following a unit differential protection operation, the unit and its associated line to the switchyard should not be re-energized until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.17 Auxiliary and Main Transformer Sudden Pressure (63)

Large power transformers are normally equipped with either gas- or oil-type sudden pressure relays to quickly detect internal transformers faults in order to mitigate the possibility of tank ruptures and fire in mineral oil transformers.

> **NOTES:** Transformer sudden pressure relays must be taken out of service before work is performed that may affect the internal pressure of the transformer, for example, adding nitrogen gas, adjusting gas regulators, or any work that would allow the gas to vent to atmosphere. Following a sudden pressure protection operation, the transformer should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.18 Zone 1 Impedance (21)

Some designs apply a zone 1 impedance relay that looks from the switchyard into the generating unit to provide backup protection for the unit differential or the high voltage line feeder differential relay. This protection can detect electrical short circuits in the unit breakers, line from the switchyard to the main step-up transformer, main step-up transformer, isolated phase bus, and generator and instantaneously operate to isolate faults. In the case of reserve or startup auxiliary power transformers fed from the switchyard, it will back up feeder and transformer differential relays and will protect the switchyard breakers, line to the transformer, and the transformer itself from short circuit conditions.

NOTE: Following a zone 1 protection operation, the unit or transformer should not be returned to service until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.19 Breaker Failure (50BF)

Breaker failure protection is normally provided for switchyard circuit breakers and in the newer technology, digital relay breaker failure protection can also be used for stuck breakers on the generator bus. Basically, if the breaker does not open in a specified amount of time after a trip signal is applied and a high level of current is flowing through the breaker, the breaker failure relay logic will automatically open adjacent breakers in order to isolate the stuck breaker condition.

NOTE: Following a breaker failure protection operation, the unit and its associated line to the switchyard should not be re-energized until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.20 Transformer Overcurrent (51)

Auxiliary power transformers (generator bus fed or system fed) are normally equipped with primary side overcurrent relays to back up the differential protection and, more importantly, to provide stuck breaker protection in case the low side breaker fails to operate to clear a faulted condition.

NOTE: Following an auxiliary transformer high side overcurrent protection operation, the transformer should not be re-energized until an investigation is completed by engineers or technicians and the problem is resolved.

6.1.10.21 DC Low Voltage (27DC)

Critical protection DC circuit voltage levels should be monitored to ensure that the protection can operate properly. Whenever the DC voltage level is at or below the set point threshold, an alarm will be initiated.

NOTE: Following a DC low voltage alarm, plant operators, electricians, and technicians should immediately investigate and resolve the problem or remove the protected equipment from service.

6.1.10.22 DC High Voltage (59DC)

Critical protection DC circuit voltage levels should be monitored to ensure that the protection can operate properly. Whenever the DC voltage level is at or above the set point threshold, an alarm will be initiated. This would normally indicate that the battery charger failed in a raise voltage direction.

> **NOTE:** Following a DC high voltage alarm, plant operators, electricians, and technicians should immediately investigate and resolve the problem or remove the protected equipment from service.

Many generating stations at this time are not equipped with all of the foregoing protection functions; some of these protections are available only in the newer technology multifunction digital relays. However, many stations will be upgraded with the newer technology relays in the future.

6.2 Operation of Large Power Transformers

6.2.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the routine operator inspection of power transformers (500 kVA and larger).

Good operating practices are important to obtain the best service and performance. Every transformer failure represents a potential hazard to personnel and other equipment in the plant and can cause a forced outage of the unit.

6.2.2 Operator Inspections

It is the responsibility of operations to establish and maintain scheduled routine inspections of all large transformers. In general, an inspection frequency of once per day is recommended.

The following daily checks are recommended:

- Oil leaks (where applicable).
- Proper nitrogen pressure (where applicable).
- Abnormal noise.
- Proper oil level in tanks and electrical bushings (where applicable).
- Explosion relief device semaphores or targets (where applicable).
- Proper oil pump operation (where applicable).
- Proper fan operation (where applicable).
- Condition of high and low side overhead-connected bushings, insulators, and lightning arrestors (where applicable). Check the bushings and insulators for external contamination, white banding

(if silicone coated), audible spitting, corona activity, or unusual radio interference.

- If switching provisions are provided, change over cooling fans and circulating pumps to ensure equal running hours (usually monthly).
- Inspection of security fences, doors and gates, locks, warning signs, and so on, for integrity/operation.
- Silica gel breather desiccant crystal color (where applicable).
- Top oil temperature gauge values. If the drag-hand is above normal range, log the value and reset max pointer afterward. Investigate why the maximum temperature value was reached.
- Winding temperature gauge values (where applicable). If the drag-hand is above normal range, log the value and reset max pointer afterward. Investigate why the maximum temperature value was reached.
- Neutral grounding resistors/reactors (where applicable). Check for corrosion, oil leaks, and condition of associated bushings and insulators.

When abnormalities are found that could cause a major failure of the transformer, steps should be taken to quickly remove the equipment from service. Less serious conditions that require maintenance or repair should be identified on a maintenance order and taken care of at the first practical opportunity.

6.2.3 Sudden Pressure Relays

Sudden pressure relays should be taken out of service whenever work is to be performed that may affect the internal transformer pressure. Examples of when sudden pressure relays should be made nonautomatic include the following:

- Adding nitrogen gas to the transformer
- Adjusting the nitrogen gas regulator
- Replacing the nitrogen gas bottles
- Removing the transformer top filter press inlet plug
- Adding oil to the transformer
- Performing work that may allow the nitrogen to vent or escape to atmosphere
- Performing work on the sudden pressure relay or associated circuitry

6.2.4 Transformer Differential or Sudden Pressure Relay Operations

After a transformer sudden pressure or differential operation, the transformer should be thoroughly tested prior to re-energization, unless it can be determined that the protection operation was due to a calibration or setting error, improper current transformer circuitry, or a failed relay.

Where the integrity of the main step-up transformer or auxiliary transformer remains suspect because of questionable repairs or unknown reasons for the relay operation, the transformer should be energized once for test. Energizing the generator step-up transformer from the system (preferably with a dedicated transmission line) with the generator isolated via open isolated phase bus links or generator breaker has the following advantages:

- A soft energization from the generator may not provide enough fault current to quickly actuate the protection, and the damage to the transformer may be greater.
- Energizing the transformer from the generator potentially exposes the generator to a fault.

6.2.5 Emergency Cooling and Loading

Running service water on the exterior surfaces of transformers to reduce operating temperatures is a practice that should only be performed during emergencies and is not generally recommended for the following reasons:

- Service water contains a significant amount of dissolved solids that can form a temperature insulation barrier on the heat exchangers and other exterior surfaces, forcing the transformer to continually operate at higher temperatures.
- Service water is corrosive to transformer heat exchangers and other accessories.

Where it appears that it is necessary to use service water from time to time, a transformer load-ability study can be performed to see if the transformer can operate at higher temperatures, negating the need for the service water.

In general, transformers can be loaded beyond their nameplate ratings for short durations with no or a very small loss of life. Many transformers can carry 140% of full load for 2.0 hours with a very small loss of life. However, the permissible short time load-ability varies depending on the design particulars of the specific transformer. An engineering study should be completed before transformers are operated above their rated load to substantiate that the loss of life is acceptable and that the associated buses, cables, and breakers can also carry the increased load.

6.2.6 Oil Pump Operation

Electrostatic voltage transfer is the phenomenon by which a charge develops between the oil and the insulation systems of a transformer, when the transformer is de-energized, and oil is circulated by the oil pumps.

Running oil pumps on de-energized transformers should be limited to 10 minutes. This is to prevent failure of transformers from electrostatic charging and subsequent tracking of the insulation systems. If additional operation of the pumps is required, a minimum wait time of 2 hours should be followed before operating the pumps again.

6.3 Operation of Large Electric Motors

6.3.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the routine operator inspection of switchgear-fed motors (100 HP and larger).

Good operating practices are important to obtain the best service and performance. Every motor failure represents a potential hazard to other equipment in the plant and may cause a forced outage of the unit.

6.3.2 Operator Inspections

It is the responsibility of operating personnel to establish and maintain scheduled routine inspections of all large motors. In general, an inspection frequency of once per day is recommended.

The following checks are recommended for *running* motors:

- Abnormal noise levels
- Increase in bearing vibrations
- Increased operating temperatures of bearings or stator
- Status of lubricating oil, that is, contamination, proper levels, temperatures, and pressures
- Cleanliness of exterior surfaces
- Cleanliness of air filters
- Obstruction of air intakes

The following checks are recommended for de-energized *standby* motors:

- Lubricating oil system in proper standby condition
- Motor heaters in service (where applicable)
- Power and control circuits in proper standby condition
- Cleanliness of exterior surfaces
- Cleanliness of air filters
- Obstructions that would interfere with the starting of the motor

Maintenance orders should be prepared for any anomalies found during the foregoing inspections.

6.3.3 Starting Duty

Generally, induction motors should be limited to the following starts:

1. Two starts in succession, coasting to rest between starts with the motor initially at ambient temperature.
2. After two successive starts, a minimum 1-hour cooling period should be provided before a third start. The motor can be at rest or running during the cooling period.

The preceding information is to be used as a guide. Manufacturers' specifications may be more stringent or liberal and have precedence over this general guideline.

6.3.4 Heaters

Many large motors are equipped with heaters to prevent moisture buildup in the windings. The heaters should automatically switch on when the motors are de-energized. Motor heater circuits should be monitored by ammeters or current-driven sensor LEDs to provide indication that the heaters are functioning properly. Operations should routinely verify that the heaters are working when the motors are de-energized. When it is found that the heaters are not working properly, the motor stator insulation should be tested with a megger prior to returning it to service.

6.3.5 Protection

Operation of motor protective relays should not be taken lightly. The following investigation steps should be completed before allowing restarts of motors following protective relay operations.

6.3.5.1 Instantaneous Phase Overcurrent Tripping

Instantaneous phase overcurrent relay minimum trip points should be set well above surge and locked rotor values for the motor. An instantaneous target and corresponding trip indicates that either the electrical protection malfunctioned or was set improperly, or a permanent ground (solidly grounded systems only) phase-to-phase or three-phase electrical fault exists in the cable or motor. The motor should not be re-energized; this is to avoid aggravating damages and overstressing the plant electrical system until the cause of the relay operation can be determined and repaired or until reasonable testing to prove the electrical integrity of the motor or cables has been completed.

6.3.5.2 Time Phase Overcurrent Tripping

Time overcurrent targets and corresponding trips are usually caused by mechanical problems in the motor or driven equipment, control anomalies, or malfunctioning or improperly set protective relays.

If the motor trips on time overcurrent during *starting* (rotor thermally stressed):

- Verify that the motor was properly unloaded during the starting cycle.
- Visually inspect bearings and lubricating systems for both the motor and the driven equipment.
- Rotate the motor and driven equipment (where practical) to verify mechanical freedom.

If no mechanical cause for the relay operation can be determined, complete the maintenance testing discussed in Chapter 7.

If the reason for the trip cannot be determined after testing and allowing for a minimum 1-hour cooling period, restart the motor for test with an operations or maintenance person at the motor location (safe distance) to prove rotational capability.

If the motor trips on time overcurrent while *running* (stator thermally stressed):

- Review bearing temperatures (where possible).
- Visually inspect the motor and driven equipment.
- Review associated operating parameters for acceptable ranges prior to the trip.
- Perform the maintenance testing discussed in Chapter 7.

If no cause for the relay operation can be found after completing the recommended testing and allowing for a minimum 1-hour cooling period, restart the motor for test and closely monitor the running amperes.

6.3.5.3 Feeder Ground Tripping

Feeder ground targets and corresponding tripping would not occur unless there is a protective relay malfunction or permanent cable or motor insulation single phase-to-ground failure. The motor should not be re-energized until the cause of the failure can be determined and repaired or until reasonable testing to prove electrical insulation integrity has been completed.

6.4 Operation of Auxiliary System Switchgear

6.4.1 Purpose

The purpose of this guideline is to provide suggested practices for the operation and inspection of medium voltage (2 to 13.8 kV) and low voltage (200 to 480 volt) draw-out switchgear circuit breakers and contactors.

Good operating practices are critical to obtain the best service and performance from plant equipment and to ensure a safe environment for plant personnel.

6.4.2 Operator Inspections

It is the responsibility of operating personnel to establish and maintain scheduled routine inspections of all plant switchgear. Circuit breakers, contactors, and buses must be maintained clean and dry to reduce the possibility of insulation failures that can result in explosions and fire. In general, an inspection frequency of once per day is recommended.

The following daily checks and inspections of switchgear locations are recommended:

- Dropped or actuated protective relay targets. Targets found should be reset and recorded in the control room log book.
- Audible noise from electrical arcing.
- Unusual smell from overheated or burning insulation.
- Moisture intrusion, for example, roof leaks, water on the floor.
- Status lamps and semaphores are working properly.
- Pressurizing room fans and dampers are functioning properly to mitigate moisture intrusion and other contamination.
- Switchgear room doors closed properly to mitigate contamination.
- Switchgear cubicle doors are closed to mitigate contamination.
- Panels for accessing breaker racking mechanisms, cable terminations, and other purposes are closed to mitigate contamination.
- Breakers and contactors are kept in their respective cubicles or in special enclosures (usually equipped with heaters) designed to keep the equipment clean and dry.
- Switchgear room lighting is functioning properly.
- Cubicle labeling is consistent with plant policy and accurately describes the source, tie, and feeder positions.
- Rack-in tools and protective safety gear are stored and maintained properly.
- Housekeeping is performed often enough to keep the room clean and orderly.

Maintenance orders should be prepared for any anomalies found during the foregoing inspection process.

6.4.3 Protection

Protective relays are coordinated in a way that only those circuit breakers or contactors that need to be operated to isolate faults are automatically tripped open. This allows the maximum amount of equipment to remain in-service and reduces the impact to on-line generating units. It also provides an indication as to the location of the electrical fault.

Electrical faults in transformers, motors, buses, cables, circuit breakers, and contactors are permanent in nature, and protective relay operations must be thoroughly investigated before re-energizing the equipment. Electrical short circuits are usually in the range of 15,000 to 45,000 amps depending on the size and impedance of the source transformer. Re-energizing faulted electrical apparatus always results in more extensive damage and commonly causes fires. Therefore, the equipment should not be re-energized until a thorough investigation is completed by engineering and maintenance personnel. Source and tie breaker overcurrent relays should be set high enough to handle bus transfer conditions where all connected motors may be in an inrush or starting condition. Consequently, these relays do not always provide ideal thermal overload protection, and operations must rely on transformer temperature alarms, ammeters, or DCS alarms for that purpose. Accordingly, the overcurrent tripping of a source or tie circuit breaker usually indicates a short circuit and not an overload condition.

6.4.3.1 Load Feeder Overcurrent Protection

Load feeders are equipped with fast-acting instantaneous overcurrent elements (fuses for contactors) that will clear short circuits in the cables or load (motors or transformers) by isolating the faulted circuits before source and tie breaker overcurrent relays can operate.

6.4.3.2 Load Feeder Ground Protection

Designs that limit the ground fault current (usually around 1000 amps) apply separate ground relays that will actuate for ground faults only. These relays trip with very short time delays to isolate the grounded feeders before source or tie circuit breaker ground relays can operate.

6.4.3.3 Source and Tie Overcurrent Protection

Source and tie breakers are not equipped with instantaneous tripping elements. They rely on time delay to achieve fault coordination with downstream buses and loads. Typically, these relays are timed at maximum three-phase short circuit current levels and are set to operate in 0.4 to 0.8 seconds. Normally, the relays have an inverse time characteristic, and lower current levels will increase the time delay for all relays correspondingly. Typically, the tie breaker to another bus will be set to operate in around 0.4 seconds and the source transformer low side breaker in around 0.8 seconds. Designs using two tie breakers in series often have the same relay settings on each breaker, and either one or both tie breakers may operate for faults downstream of both tie breakers. The source and tie overcurrent relays protect the buses and all breakers that are racked into the buses. They also provide backup protection if a feeder breaker fails to clear a faulted cable or load.

6.4.3.4 High Side Source Transformer Overcurrent Protection

The source transformer high side overcurrent relays are normally set to operate for maximum three-phase short circuits on the low voltage side in around 1.2 seconds. This provides enough time delay to coordinate with low voltage or secondary side overcurrent relays. The relays usually have an inverse time characteristic, and lower current levels will increase the time correspondingly. The source transformer high side overcurrent relays assume that the fault is in the transformer, low voltage side connecting buses or cables, or in the low voltage circuit breaker and will trip all equipment necessary to isolate the fault. In the case of UATs, which are usually equipped with differential protection, the high side overcurrent relays will also provide a complete electrical trip of the unit and main step-up transformer. The high side overcurrent relays also provide stuck breaker protection if the low side breaker fails to interrupt a fault.

6.4.3.5 Source and Tie Residual Ground Protection

Designs that limit the ground fault current (usually around 1000 amps) apply separate ground relays that will actuate for ground faults only. Source and tie breaker ground relays are not equipped with instantaneous tripping elements. They rely on time delay to achieve fault coordination with downstream buses and loads. Typically, these relays are timed at maximum ground fault current levels and are set to operate in 0.7 to 1.1 seconds. Normally, the relays have an inverse time characteristic, and lower current levels will increase the time delay for all relays correspondingly. Typically, the tie breaker to another bus will be set to operate for 100% ground faults in around 0.7 seconds and the source transformer low side breaker in around 1.1 second. Designs using two tie breakers in series usually have the same relay settings on each breaker, and either one or both tie breaker ground relays may operate for ground faults downstream of both tie breakers. The source and tie breaker ground relays protect the buses and all breakers that are racked into the buses. They also provide backup protection if a feeder breaker fails to clear a grounded cable or load.

6.4.3.6 Source Transformer Neutral Ground Protection

Designs that limit the ground fault current (usually around 1000 amps) apply separate ground relays that sense the ground current flowing in the transformer neutral. Only ground faults will actuate these relays. The source transformer neutral ground relay is normally set to operate for maximum ground faults in around 1.5 seconds. This provides enough time delay to coordinate with the source and tie breaker ground relays. The relay usually has an inverse time characteristic, and lower current levels will increase the tripping time correspondingly. Transformer differential protection may not operate for ground faults in this zone because the limited amount of ground current in this type of scheme may not be high enough to operate the relays. The neutral ground relay is designed to isolate ground faults on the low voltage or secondary side of the source transformer. This includes the transformer low voltage winding, low voltage circuit breaker, and connecting buses or cables. The neutral ground relay will also back up the low side breaker if it fails to clear a ground fault condition.

6.4.3.7 Alarm-Only Ground Schemes

These schemes limit the ground fault current to just a few amps. Typical values are 1.1 amps for 480 volt systems and 3.4 amps for 4 kV systems. On wye connected source transformers, the neutral is normally grounded through a grounding transformer. On delta connected source transformers, the ground current is usually supplied by three transformers connected grounded wye on the primary and broken delta on the secondary. In both cases, voltage relays are applied on the secondary sides of the grounding transformers to alarm for ground conditions. In the later scheme, blown primary fuses to the ground detector transformers can cause an alarm condition. Both relay schemes provide alarms (typically 10% and higher) for all grounded apparatus on the particular electrical system, including the source transformer low voltage or secondary windings, and all connected buses, cables, breakers, potential transformers, and loads.

When one phase of a three-phase system has a 100% ground, the voltage to ground on the other two phases almost doubles (1.73 times higher). This means that the electrical insulation for all equipment on the system has to withstand a much higher voltage to ground when one of the other phases is grounded. This voltage is normally above the continuous insulation rating of installed cables and other electrical apparatus. Consequently, plant operators are expected to isolate and clear ground faults within a relatively short time period. If the ground fault is not cleared in a timely manner, it may develop into a high current short circuit condition if another phase fails to ground from the higher operating voltage to ground. Because short circuits often result in explosions, fire, and loss of generation, it is in the interest of operations to have a predeveloped plan for quickly isolating grounds. This usually involves switching off nonessential loads, transferring to a different source transformer, and reducing generation to a point where other loads can be taken out of service.

6.4.4 Switchgear Bus Transfers

6.4.4.1 Paralleling Two Sources

Paralleling two different sources is the preferred method of transferring from one source to another. This method is not stressful to motors, is bumpless, and does not jeopardize a running unit. However, in many designs, the amount of short circuit current available during the parallel exceeds the interrupting capability of feeder breakers. Source and tie breakers will not be affected, but feeder breakers may not be able to clear close in faults and the breakers may be destroyed in the process. Consequently, the duration of parallel should be kept to a minimum (a few seconds) to reduce the exposure time and likelihood of a feeder fault occurring. Parallel operations should not be performed if the voltage phase angles between two systems are out of phase by 10 degrees or more, as extrapolated from a synchroscope. Depending on the impedances of the transformers involved, phase angle differences as little as 10 degrees can cause more than rated current to flow during parallel operation. The higher current may cause the operation of source or tie overcurrent relay and the resulting loss of the bus and generation. Typically, this is more of a problem when the generating unit feeds one system and the reserve, or startup transformer is fed from a different system. Reducing generation will normally bring the phase angles closer together as the generator's power angle reduces from the lower load.

6.4.4.2 Drop Pickup Transfers

Drop pickup or switch time transfer schemes are potentially damaging to motors and may cause the loss of a running unit or interruption of an operating process if the new source breaker fails to close after the prior source breaker trips open. When a bus is de-energized, the connected motors act like generators and provide a residual voltage to the bus. This voltage usually collapses in approximately 1 second. However, drop pickup transfers are much faster than 1 second, and the residual voltage can add to the new source voltage. If the vector sum of the two voltages exceeds 133% of motor rated voltage, the transfer can reduce the operational life of the motors involved.

6.4.4.3 Automatic Bus Transfer Schemes

Automatic bus transfer schemes are normally designed to reduce motor stress during transfer conditions and to coordinate with fault relays. Coordination with overcurrent relaying is achieved by initiating the transfer after the source circuit breaker trips open. If overcurrent relays trip the source breaker (indicating a bus fault), the automatic transfer will be blocked. Additionally, these schemes normally apply residual voltage and/or high-speed synchronizing check relays that will not allow transfers unless the vector sum of the residual and new source voltages are below 133%. Usually these schemes will time out if the transfer is blocked by 86 lockout relays. However, if that is not the case, operations should verify that the automatic transfer scheme is disarmed before resetting bus 86 lockout relays.

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7

Electrical Maintenance Guidelines

The maintenance guidelines are based on over 40 years of electrical maintenance and engineering experience in generating stations. They represent a procedural effort to improve the availability of generating stations and large industrial facilities and reduce hazards to plant personnel. Some of the text was developed following actual failures in stations and some to try to mitigate equipment failures reported by the industry in general. However, there are a number of areas where the guidelines may need to be revised by a particular generating station to meet their specific requirements. Some of these areas are presented below:

- The guidelines are general in nature and manufacturer's recommendations for their equipment have precedence over the guidelines.
- There may be government regulatory agencies whose recommendations have priority over the guidelines; for example, the Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), Occupational Safety and Health Administration (OSHA), National Electrical Code (NEC), and so forth.
- The guidelines assume that electricians, technicians, engineers, and contractors are well trained and qualified to perform the suggested tasks and all appropriate safety measures are taken.
- The station may have unusual environmental conditions that need to be accounted for in the guidelines.

The guidelines represent a good starting document. However, they should be treated as a work in progress that reflects the every changing government regulations, site-specific experience and industry experience in general.

7.1 Generator Electrical Maintenance

7.1.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the inspection, care, and electrical maintenance of generators.

The guideline is aimed at electrical specialists and does not cover generator support systems that are normally maintained by mechanical crafts, including seal oil systems, seals, bearings, blowers, rotor balancing, water coolers, gas and air cooling systems, leak detectors, and stator inner cooled water systems.

7.1.2 Routine On-Line Slip-Ring Brush-Rigging Inspections

NOTES: The rotor ground fault protection should be taken out of service whenever maintenance is performed on the brush rigging to avoid nuisance alarms or trips and to reduce the voltage reference to ground. Low voltage rubber gloves should be worn prior to contacting any energized conductors. The ground detector should be placed back into service as soon as the brush-rigging work is completed. All activities are to be coordinated with the control room personnel.

Station maintenance should be performed on excitation system brush rigging when:

- Before a unit is returned to service after an electrical fault that results in a unit trip.
- At least once per week on in-service and standby units (on turning gear), preferably before the weekend on Friday.

NOTE: Information should be recorded about the condition of the brushes and brush holders and general visual findings during the inspection. An equipment-specific form should be prepared for each machine that accommodates the number of brushes and other design details. The as-found information should be entered while performing the inspection steps delineated below.

The following checks should be performed during the inspection process:

- Check brush leads (pigtails) for looseness, heating (discolored leads), and frayed wires.
- Check for proper and uniform brush tension. (Once a month, a spring tension scale should be used to spot-check and verify recommended tension).
- Check for brush wear. Brushes should be replaced when 75% of their useful life has been expended. If spring tension becomes less than recommended and the springs are in good condition, the brushes may have to be replaced earlier.
- In general, no more than 20% of the brushes on a polarity should be replaced at one time with the unit in-service. Ample time should be allowed for the new brushes to seat properly before replacing additional brushes. Under no circumstances should brushes of different

grades or manufacturers be mixed on the same polarity. If special jigs for bedding the brushes are available at the site, up to 50% of brushes can be replaced at one time, if properly bedded.

- Lift each brush approximately one-quarter inch and gently allow it to return to the operating position under normal spring pressure. Remove brushes showing a tendency to stick or bind and correct the cause.
- Pull out a single brush from each polarity and observe the face for etching and excess powdering.
- Feel the top of each brush and check for running smoothness.
- Check for sparking or arcing.
- Inspect brushes for mechanical wear, cracks, and hammerhead or anvil.
- Inspect integrity of springs and clips.
- Using dry air (not to exceed 35 psi), remove accumulated carbon dust from the brush rigging. A filter mask should be worn during this process to mitigate inhalation of carbon fibers.
- Spot-check 10% of the brushes on each polarity with a direct current (DC) clamp-on ammeter for uniformity in current loading.
- The appearance of rings should be clean, smooth, and highly polished. A dark color does not necessarily indicate a problem. Look for streaking, threading, grooving, and a poor film. Collector ring-polishing or brush-seating procedures may be accomplished by using canvas or brush seating stones when necessary. A stroboscope will go a long way in aiding the visual inspection of the collector rings with the unit in operation.

NOTE: Grinding of collector rings to remove metal should not be performed on on-line energized units (excitation applied to the field) by plant personnel. However, contractors with a proven record, using specially designed stones and a vacuum system to remove the particulate and following proper procedures, have been successfully used to grind the collector rings on-line.

- Check the brush compartment for cleanliness, loose parts, contamination by oil or dirt, or other conditions that may suggest a source of trouble. If an air filter is installed, check for cleanliness of the filter and proper seating of the filter, and change or clean if necessary.
- Problems found during the foregoing inspection steps should be corrected to the extent possible with the unit in-service. Needed maintenance or repairs requiring a unit outage should be identified on a maintenance order.

7.1.3 Inspection of Rotor Grounding Brushes and Bearing Insulation

If accessible with the machine on-line, at the same time the excitation brush rigging is inspected, the condition of the turbine rotor grounding brushes or braids should be checked. The integrity of the grounding elements is essential for minimizing shaft-voltages and shaft or bearing currents.

On some designs with pedestal bearings and sandwich-insulation construction, it is possible to measure the insulation resistance with the unit on-line. When possible, this insulation should be tested for proper values during the inspection. According to the literature, it should fall between 100 kΩ and 10 MΩ or greater.

In some pedestal-bearing arrangements, it is possible to assess the integrity of the insulation by measuring the voltage across the bearing insulation with a high-impedance voltmeter. If the grounding brush is lifted during the test, the shaft voltage is impressed on the bearing insulation. Therefore, if the reading is zero, the integrity of the insulation is compromised. Experience will show what voltage magnitudes to expect for a particular machine. It is not uncommon that shaft voltages are as high as 120 volts.

> **NOTE:** On some designs, the bearing insulation can only be measured during the assembly of the mechanical components. Accordingly, it is important that the measurements be completed at the appropriate time or reassembly sequence. Refer to the original equipment manufacturer (OEM) for specific recommendations for the testing of the bearing insulation.

7.1.4 Routine Unit Outages

The following maintenance is recommended during unit outages:

- Brushes should be lifted on generator collector rings whenever units are off turning gear in excess of 24 hours to 1-week duration to mitigate brush imprinting (depending on the local environmental conditions and the plant's experience). Experience has shown that brush imprinting may result in ring polishing or grinding requirements that shorten the life of the rings.
- Inspect the rings for condition and protect them from the elements to prevent physical damage and oxidization when applicable. A PVC (polyvinyl chloride) film and corrugated cardboard overwrap can provide a protective cover.
- At the beginning of each shutdown and weekly thereafter, test for hydrogen leaks (if applicable) around the collector rings and outboard radial terminal studs.

During routine shutdowns, or at approximately 3-month intervals, accomplish the following maintenance:

- Thoroughly clean the brush rigging and slip rings.
- Check all brush faces and change any brushes that are less than one-third the original length. If more than 20% of the brushes require replacement, they must be seated.
- Thoroughly check the brush rigging for loose parts.
- Check the brush holder to collector ring clearance, which should be uniform and within the manufacturer's tolerances (typical value is 3/16 of an inch from brush-holder to ring). Brushes should not be allowed to ride closer than 1/8 inch from the edge of the collector rings, and the average centerline of the brushes in the axial direction should coincide with the centerline of the ring when the machine is at operating temperature.
- The cooling grooves for generator collector rings should be inspected for proper depth. If carbon dust is found in the grooves (oftentimes it combines with oil vapor escaping through adjacent bearing seals to form a hard compound), carefully remove to reinstate the cooling capability of the grooves.
- With the unit off turning gear and the brushes lifted, and after completing a thorough cleaning of the insulating material beneath the collector rings, megger the field and perform a DC resistance and alternating current (AC) impedance test of the field winding. The resistance measurements should be corrected to ambient temperature and compared to previous data by an experienced person. Impedance and resistance changes caused by rotor shorted turn and connection problems may be slight.

7.1.5 Overhauls

Generators are usually refurbished whenever their respective turbines high pressure or low pressure (HP or LP) are overhauled. The following maintenance is recommended during major overhaul outages:

- Normally, experienced personnel, contractors, or both, will remove the generator rotor from the bore to facilitate thorough stator and rotor inspections. Care must be taken to mitigate moisture and contaminant intrusion of both the rotor and stator during the outage. It is customary to enclose the removed rotor in a canvas tent and provide canvas flaps that cover the bore openings at each end of the machine for environmental protection. Additionally, where temperature and humidity could be a problem, heated dry air should be blown through the stator bore and the temporary rotor enclosure to maintain these components in a dry condition. Alternatively, recirculating dehumidifiers could be used for long maintenance periods.

- The rotor and stator inspections should be completed by engineers or specialists with prior experience in inspecting generators.
- The outside diameter (OD) surfaces of 18-5 retaining rings should be nondestructive examination (NDE) tested for stress corrosion pitting and cracking during major overhauls. When there is evidence of abnormal moisture intrusion or moisture-induced pitting on the OD of 18-5 rings, they should be removed to facilitate NDE inspections of the inside surfaces. The OD of 18-18 retaining rings should also be NDE tested during major overhauls. If any abnormal cracking or anomalies are found on the OD surface areas, the ring(s) should be removed and NDE testing of the inside surfaces performed. Recently, 18-18 rings have been found to be susceptible to stress corrosion cracking when contaminated with chlorides. Thus, they need to be kept away from such contamination and cannot be assumed to be free of stress corrosion–induced cracking.
- Generators with 18-5 retaining rings should be equipped with continuous dew point monitoring systems and alarms during overhauls to ensure that moisture intrusion problems are quickly identified, recorded, and mitigated.
- The generator rotor bore at the excitation end of hydrogen-cooled machines should be pressure tested with clean dry air or an approved inert gas at 125% of rated hydrogen pressure during overhauls. The pressure is normally applied to the bore plug opening. The bore should be able to hold capped (isolated from air/gas supply) pressure for 2 hours without an indication of a leak. Older machines may be equipped with hydrogen seals on the in-board radial conductor studs only, and the collector ring area or outboard radial studs will need to be sealed off with a can or other means to facilitate the pressure testing. It is prudent to stress-check the integrity of the rotor bore plug itself, which, in some cases, have been found deficient. This plug often is forgotten during inspections, but it has the potential for hydrogen leaks, so it should be inspected, and replaced if necessary, during major overhauls.
- All generator monitoring instrumentation should be calibrated during overhauls and functionally tested at 2- to 3-year intervals in between overhauls.
- Brushless excitation system diodes and associated fuses should be thoroughly cleaned and inspected during overhauls and at 2- to 3-year intervals in between overhauls. Diodes and fuses requiring replacement should be replaced with identical manufacturer's models and weight measured before and during replacement to ensure that rotor balance is not affected. Where identical diodes or fuses cannot be supplied, the complete set should be replaced with a new matching set.

- Electric insulation tests would normally be performed on stator and rotor windings at the beginning of the outage, when the unit is still assembled and warm (under hydrogen pressure when applicable). This will allow more time to complete any required repairs during the outage window and ensure that the machine is in a dry condition for the testing.
- When applicable, generator heaters should be left switched-on to avoid moisture ingress. The space heaters must be switched off whenever personnel are performing inspections or work in the interior stator areas.
- If applicable, lead-box drain-lines should be inspected for blockage and cleaned if necessary. Liquid level-detection systems should be checked for proper alarms and site glasses cleaned.

7.1.6 Vibration

Shorted turns in generator two and four pole cylindrical rotor field windings can contribute to vibration problems due to rotor thermal bending from uneven heating associated with nonsymmetrical DC current flow and watt losses in the field windings. Shorted turns can also cause unbalanced magnetic flux in the air gap that can aggravate vibration problems.

Since vibration signature analyses for generator rotor shorted turn problems is not always an exact science, it is desirable to have confirming data from other testing before proceeding with very costly disassemblies and repairs of large machines. Additional tests for confirming the existence of shorted turns in generator rotor field windings are commonly performed before committing to expensive repairs. At this time, the following three test procedures are generally used in the industry to help verify whether or not generator field windings have shorted turns:

- Thermal Stability Testing—Involves changing generator-operating parameters (watts, vars, and cooling) and recording and analyzing the impact on rotor vibration signatures.
- Flux Probe Analysis—Utilizes an installed air gap probe to measure and analyze the magnetic flux from each rotor slot as it passes by the location of the sensor. Some generators are permanently equipped with flux probes and many are not. Installing the probe normally requires a unit outage, especially with hydrogen-cooled machines.
- RSO (Repetitive Surge Oscilloscope) Testing—Involves applying a succession of step-shaped low voltage pulses that are applied simultaneously to each end of the field winding. The resulting reflected waveforms can be viewed on dual channel analog or digital scope screens as two separate waveforms, or after one of them is inverted, and both summed as a single trace. If no discontinuities are present

in the winding (due to grounds or shorted-turns), both traces will be nearly identical and if inverted and summed, a single trace will be displayed as a horizontal straight line. Any significant discontinuity arising from a shorted turn will be shown as an irregularity or anomaly on the summed trace.

It should be noted that the foregoing testing (vibration analysis, thermal stability, flux probe analyses, and RSO testing) by themselves do not provide absolute certainty that there is a shorted turn problem in the generator rotor. However, when confirmed by other testing, the probability of the field winding being the cause of the vibration problem increases significantly. Shorted turn anomalies can be masked if they are near the center of the winding or otherwise balanced, if there are multiple shorted turns, if they are intermittent due to centrifugal force or thermal expansion and contraction, if there are grounds, and if there are other contributors to the overall machine vibration levels.

RSO testing has some advantages over other testing in that it can be used periodically during rewinds to verify that windings are free of shorts, on both at rest and spinning de-energized rotor windings.

7.2 Transformer Electrical Maintenance

7.2.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the inspection, care, and maintenance of oil-filled and dry-type power transformers 500 kVA and larger, including on-site spare units.

7.2.2 Inspections

The systems and components identified below should be inspected by maintenance personnel on in-service and spare transformers at 2- to 3-year intervals, or at intervals specified by the manufacturer, if they happen to be shorter than 2 years.

- Check heat exchangers and associated components for oil leaks, rust, exterior paint condition, cleanliness of airway passages, and deterioration of cooling fins.
- Check main and conservator oil tanks for oil leaks; correct level, rust, and exterior paint condition. Ensure sight glasses are clean and oil levels are clearly visible.

- Control cabinets should be cleaned, wiring checked for tightness, and motor contactor contacts inspected, cleaned, and dressed as required. Fan and pump loads should be meggered and started to prove proper fan rotation and operation of oil flow indicators. Molded-case circuit breakers should be exercised several times to prevent frozen mechanisms. Motor load current and phase balance should be checked with a clamp-on ammeter. Heaters in the control panel should be checked for proper operation. Care should be taken not to enable trip functions during this inspection.
- Each transformer alarm should be functionally tested to prove proper operation. Care should be taken not to activate a trip function during the alarm testing.
- Check high and low voltage bushings and insulators for physical condition and cleanliness of porcelain or coatings. Check bushing oil level, where applicable, and leaking flanges. If the inspection identifies the need of adding oil during the next outage, care should be taken to use new clean, dry oil of identical or equivalent characteristics.
- Where applicable, verify that a positive nitrogen pressure blanket is maintained within the limits specified by the manufacturer. Typically, low-pressure alarms are set for 0.5 psi, and normal operating pressure is around 2.0 psi.
- Perform a thermograph test of transformer and associated external electrical connections. The test should be performed when the transformer's load is greater than 25% of full load and has been over that value for at least 1 hour. Prior to the thermography testing of the cooling system, make sure all cooling pumps and fans are running for at least 1 hour (this may require switching the cooling system to manual operation).
- Transformer oil leaks should be cleaned during the inspection and mitigated to the extent possible by re-torquing bolts, tightening valve packing, applying epoxy or sealants, and by gasketing leaking bolts. Care should be taken to select sealants that do not adversely affect the transformer's oil by reacting with it or contaminating it.
- Desiccant breathers should be inspected and refurbished as required.

Required corrections that can be performed with the transformer in-service should be accomplished during the inspection. Maintenance or repairs requiring a transformer outage should be identified on a maintenance order.

7.2.3 Transformer Testing

The following tests should be performed on unit related transformers during major turbine overhauls (HP turbine for cross-compound units): Testing of transformers that serve more than one unit should be performed during major turbine overhauls of the lowest number unit. The following tests should also be performed whenever new or spare transformers are placed into service:

- Power factor test (Doble) all unit transformer windings, including bushings and lightning arrestors (except transformers with secondaries rated less than 2.4 kV).
- Resistance test all high voltage (HV) and low voltage (LV) side windings (include all tap positions to check for pyrolitic-carbon buildup on the tap changer contact surfaces).
- Test insulation (megger) of each winding to ground and between windings.
- Test winding turns-ratio(s), polarity, and excitation current (except transformers with secondaries rated less than 2.4 kV).
- Test winding impedance (except transformers with secondaries rated less than 2.4 kV).
- Test and calibrate all transformer monitoring instrumentation.

NOTES: The preceding tests, for the most part, require the transformer be disconnected from external conductors and buses. Before reconnecting, care should be taken to inspect condition of mating surfaces (clean and re-silver where required); use proper contact anti-oxidation grease; torque bolts to the proper value for the particular softer mating surface material; verify that proper joint connection is achieved. Particular care should be taken to prevent oxidization when terminating aluminum connections. Normally, after cleaning, de-oxide grease is applied and then file-carded to dislodge any oxides that might have formed.

7.2.4 Avoiding Pyrolitic Growth in Tap Changers

Pyrolitic growth is the phenomenon by which oil breaks down to an amorphous hard carbon deposit through the effects of the high electric field strength around contact blocks. Once started, it grows along the contours of the field. This growth can force the contacts apart, causing a high contact resistance that can lead to gassing and failure. To mitigate this phenomenon, the following maintenance activities are recommended:

- *No-load tap changers:* At least once every 2 years, or more often where experience indicates that it is necessary. No-load and off-circuit tap changers should be operated through the entire range of taps, no less than six times. The transformer should be de-energized during this operation. Care must be taken to return the tap to the proper operational position.

- *Load tap changers:* If possible, once a month or whenever an outage allows it, load tap changers should be operated through the entire range of taps. The transformer can be energized, but preferably with the low voltage breaker open to ensure that secondary system voltages do not become too high or low.

7.2.5 Internal Inspection

Internal inspections are normally only performed when it is absolutely necessary to drain the oil to perform a maintenance repair. The inspection should be completed by an engineers or specialists with prior experience in inspecting transformers.

- Conduct internal inspection of transformer for abnormal conditions or deterioration of windings, core, core-bolt tightness, insulation, blocking (winding clamping mechanisms), shields, connections, leads, bushings, and tap changer (as required). Look for arcing, carbon tracking, burning, or excessive heating decoloration and debris in tank. Perform a core ground test, where feasible. Micro-ohm (ductor) suspected bolted joints.
- Keep exposure of core and windings to air to a minimum. When core/windings are to be exposed to air for a significant time, that is, overnight, then an external dry air or dry nitrogen source should be connected to ensure positive pressure in the tank.

  NOTE: Care must be taken not to damage continuous dissolved gas analysis (DGA) monitoring systems, during draining and refilling of transformers (in particular the application of vacuum). Follow manufacturer's instructions to prevent damage to the DGA equipment during the foregoing maintenance/inspection operations.

Vacuum-dry out and oil-fill (with de-gasified/filtered oil) should be performed based on manufacturer's recommendations, test data, parametric data, and/or as indicated by the internal condition of the transformer. After dry-out of the core and windings, the transformer should be filled with de-gasified oil, followed with a tail vacuum and running of the oil-circulating pumps to remove trapped air from the pumps and core/coil assembly. Vacuum should be broken with nitrogen. These activities should only be performed by qualified personnel.

7.2.6 Electrostatic Voltage Transfer

Electrostatic voltage transfer is the phenomenon by which a charge develops between the oil and the insulation systems of a transformer, when the transformer is de-energized and oil is circulated by the oil pumps.

- Running oil pumps on de-energized transformers should be limited to 10 minutes. This is to prevent failure of transformers from electrostatic charging and subsequent tracking of the insulation systems. If additional operation of the pumps is required, a minimum of 2 hours wait should be followed.
- Oil settling before energization—oil should be allowed to settle for at least 18 hours after completing the filling process, before energization of the transformer is attempted.

7.2.7 Dissolved Gas Analysis (DGA)

When performed timely and properly, DGA of transformer mineral oil can provide an advance warning about a deteriorating condition in a transformer before a catastrophic failure occurs. DGA can indicate the present condition of a transformer by analyzing the gas contents. A long-term assessment of a transformer can be obtained by trending the results of DGA on a specific unit. Samples should be taken annually and sent to an experienced lab for analysis. In addition to DGA, the sample should be tested for dielectric quality, moisture content, and aging parameters.

The following gases are normally analyzed for DGA purposes:

- Hydrogen H2—(<101 PPM)—Possible corona
- Carbon Dioxide CO_2—(<121 PPM)—Possible decomposition of cellulose
- Ethylene (C_2H_4)—(<51 PPM)—Possible low energy spark or local overheating
- Ethane (C_2H_6)—(<66 PPM)—Possible low energy spark or local overheating
- Acetylene (C_2H_2)—(<36 PPM)—Possible arcing
- Methane (CH_4)—(<2500 PPM)—Possible low energy spark or local overheating
- Carbon Monoxide (CO)—(<351 PPM)—Possible decomposition of cellulose

The foregoing parts per million (PPM) levels are suggested for alarm limit purposes. Transformers that have gas concentrations at or higher than the alarm thresholds should be subjected to further tests and investigations and, at a minimum, DGA tested at shorter intervals for trending purposes and assessment of developing problems. See IEEE Standard C57.104 for additional information.

7.2.8 Dielectric Breakdown Test

A dielectric breakdown test of the oil should be completed during the DGA analysis. The dielectric breakdown indicates the capacity of the oil to resist electric voltage. Its capability depends mainly on the presence of physical contaminants, that is, undissolved water, fibers, and so on. The test is normally performed with a 0.040 gap per ASTM D-1816 and the breakdown values should not be less than the following:

- Apparatus <69 kV 20 kV minimum
- Apparatus 69–288 kV 24 kV minimum
- Apparatus >288 kV 28 kV minimum

7.2.9 Insulators and Bushings

Each generating station should establish appropriate intervals for washing, cleaning, or greasing or coating transformer and neutral-reactor bushings, arrestors, and insulators based on the environmental conditions present at the particular location.

Locations in a mildly contaminating area will most likely be able to pressure wash with nonconductive water at established intervals based on experience at the particular location. Hot or energized washing in general is not recommended for substations, transformers, and their associated dead-end structures because of the flushing of contamination onto lower level bushings and insulators that can cause power arcs and electrical failures.

Silicone greases are suggested for high contamination areas (plants close to the ocean or high industrial contamination areas). It is expected that most high contamination locations will need to grease insulators at 2-year intervals. White dry bands will form on the insulators and bushings when the grease is near the end of its useful life. At the first indication of white banding, arrangements should be made to remove and apply new grease to the porcelain surfaces. The grease should be applied at a minimum thickness of 1/8 inch to prevent premature white banding. Longer duration RTV materials are also available. These materials are applied once and should last for 3 to 10 years or longer. At the end of the material's useful life, it requires scrubbing or hydro/blasting for removal before another coat can be applied.

Spare transformer bushings should be stored in either a vertical position or in a horizontal position with the top end at least 18 inches (46 cm) higher than the bottom end. In either of these positions, the insulation structure of the bushing remains under oil.

7.2.10 Sudden-Pressure Relays

Transformer gas or oil sudden-pressure relays must have their trips disabled whenever work is to be performed that may affect the internal transformer's pressure, including adding nitrogen gas, adjusting gas regulator, or work that permits gas venting to the atmosphere. This should be coordinated with the control room to ensure that the relay is returned to service correctly after the maintenance work is completed.

7.2.11 Spare Transformer Maintenance

Nitrogen-blanketed spare transformers should be kept fully assembled with nitrogen pressure maintained above the oil level. CT terminals not used (including hot-spot temperature detectors) are to be short circuited and transformer-bushing terminals should be protected from the weather to prevent corrosion. Paint should be maintained on the external surfaces to prevent corrosion. For spare transformers, oil samples should be taken every 2 years for the purpose of checking for water content and dielectric quality.

Control cabinet heaters should be temporarily wired and energized to keep control cabinets dry. Temporary power to cooling circuits is also advantageous to allow momentary periodic cycling of the cooling system to exercise the fans and pumps.

7.2.12 Phasing Test

Whenever a unit main transformer is replaced with a spare or new transformer, a thorough phasing test should be performed before completing the connections to the generator. The transformer should be energized from the switchyard with the generator isolated-phase-bus links open (where applicable). Undisturbed generator bus potential transformers (PTs) or auxiliary system bus PTs, if the auxiliary transformer is also energized, can be used for in-service readings to verify proper rotation, phase angles, and voltage magnitudes.

7.3 Motor Electrical Maintenance

7.3.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the inspection, care, and maintenance of switchgear-fed induction and synchronous motors (100 HP and larger).

7.3.2 Electrical Protection

Operation of motor protective relays should not be taken lightly. The following investigation steps should be completed before allowing restarts of motors following protective relay operations.

7.3.2.1 Instantaneous Phase Overcurrent Tripping (50)

Instantaneous phase overcurrent relay minimum trip points should be set well above surge and locked rotor values for the motor. An instantaneous target and corresponding trip indicates that either the electrical protection malfunctioned or was set improperly, or a permanent ground (solidly grounded system only), phase-to-phase, or three-phase electrical fault exists in the cable or motor. Contactor-fed motors are not equipped with instantaneous protection and will blow fuses to clear short circuit conditions. The motor should not be re-energized to avoid overstressing the plant electrical system with a second fault until the cause of the relay operation can be determined and repaired, or reasonable testing to prove the electrical integrity of the motor/cables has been completed. The following investigative steps are recommended:

- Test the electrical protection for proper operation. The instantaneous trip elements are normally set for 250% of nameplate voltage locked rotor amps.
- Physically inspect the outside of the motor, cables, and connections for evidence of electrical failure, that is, odor and smoke damage.
- Perform a 1000-volt megger test of the motor and cables together from the switchgear cubicle and take a polarization index (PI). Measure the three phase-to-phase resistances and the three phase-to-phase impedances.

    NOTE: Particular care must be exercised when testing motors from switchgear cubicles, especially when the bus stabs or primary disconnects are energized.

If the foregoing testing does not indicate a problem, motors and associated cables rated 2 kV and higher should be overvoltage or hi-pot tested at the recommended routine value for motors.

If an electrical failure is found, perform a routine inspection of the associated circuit breaker. Also, the motor should be isolated from the cables to determine if the failure is in the motor or in the cables. Motors with a neutral connection brought up to the terminal box should have the neutral opened to allow each phase to be tested separately.

After the foregoing investigative steps are completed and no cause for the relay operation can be found, attempt one restart of the motor. If successful, the motor can be returned to normal service. If unsuccessful, repeat the foregoing steps and install a portable fault recorder to monitor the electrical parameters before attempting another start of the motor.

7.3.2.2 Time Phase Overcurrent Tripping (51)

Time overcurrent targets and corresponding trips are usually caused by mechanical problems in the motor or driven equipment, malfunctioning or improperly set protective relays, control anomalies, or loss of one phase of the supply.

If the motor trips on time overcurrent during *starting* (rotor thermally stressed), then perform the following:

- Verify that the motor was properly unloaded during the starting cycle.
- Visually inspect bearings and lubricating systems for both the motor and the driven equipment.
- Rotate the motor and driven equipment (where practical) to verify mechanical freedom.

If no mechanical cause for the relay operation can be determined, complete the following electrical tests:

- Test the electrical protection for proper operation. Normally, the relays are timed for 5 seconds longer than a normal starting time at nameplate voltage locked rotor amps.
- Perform a 1000-volt megger test of the motor and cables together from the switchgear cubicle. Measure the three phase-to-phase resistances and the three phase-to-phase impedances.

If the reason for the trip cannot be determined after completing the foregoing steps and allowing for a minimum 1-hour cooling period; restart the motor for test with an operations or maintenance person at a safe distance to witness rotational capability.

If the motor trips on time overcurrent while *running* (stator thermally stressed), and no problems with the driven load or control system are identified, then do the following:

- Test electrical protection for proper operation. Normally, conventional overcurrent relays are set for 125% to 140% of full load amps.
- Test control system for proper operation.
- Perform a 1000-volt megger test of the motor and cables together from the switchgear cubicle. Measure the three phase-to-phase resistances and the three phase-to-phase impedances.
- Review bearing temperatures (where possible).
- Visually inspect the motor, cable connections, and driven equipment.

If no cause for the relay operation can be found after completing the foregoing items and allowing for a minimum 1-hour cooling period, restart the motor for test after ascertaining a three-phase supply is present at the motor's source (no blown fuses), and closely monitor the running amperes.

7.3.2.3 Feeder Ground Tripping (51G)

Feeder ground targets and corresponding tripping should not occur unless there is a protective relay malfunction, or permanent cable or motor insulation single phase-to-ground failure. The motor should not be re-energized until the cause of the failure can be determined and repaired, or reasonable testing to prove electrical insulation integrity has been completed. The following investigative steps are recommended:

- Test the electrical protection for proper operation.

  NOTES: Limited current residual ground schemes (around 1000 amps for 100% ground fault) are sensitive to current transformer (CT) saturation, connection, and shorted turn problems. Accordingly, the CTs and associated circuitry should be resistance and saturation tested to prove circuit integrity. To avoid false residual ground tripping from momentary CT saturation during starting conditions, instantaneous tripping is usually disabled and the relays are normally timed to operate in around 0.3 seconds for a 100% ground condition.

  NOTE: Designs using a single CT that wraps around all three phases (zero sequence CT) are not prone to false tripping from saturation and other CT unbalance problems, and testing of the CT is not required.

- Physically inspect the outside of the motor, cables, and connections for evidence of electrical failure, that is, odor and smoke damage.
- Perform a 1000-volt megger test of the motor and cables together from the switchgear cubicle and take a PI. Measure the three phase-to-phase resistances and the three phase-to-phase impedances.

If the foregoing testing does not indicate a problem, motors and associated cables rated 2 kV and higher should be overvoltage or hi-pot tested at the recommended routine value before re-energization.

If no cause for the relay operation can be found after completing the foregoing steps, attempt a restart of the motor. If successful, the motor should be returned to normal service.

7.3.3 Testing

The following testing is recommended when motor feeder circuit breakers are removed from their respective cubicles during circuit breaker and bus routine maintenance:

- Perform a 1000-volt megger test from the switchgear cubicle to determine the health of the motor/cable insulation systems (if surge capacitors and/or arrestors are installed, they can be left connected during the megger test). The minimum megohms for this test is 3 megohms per φ-φ kV; for example, a 4 kV motor should have at least 12 megohms, and a 460-volt motor should have at least 1.4 megohms to ground. Three (3) megohms per kV roughly translates to the IEEE recommendation (1 megohm per kV plus 1 megohm at 40° C) at typical ambient temperatures.
- Perform three phase-to-phase resistance tests to determine the condition of the electrical connections (should be within 5% of each other). A poor electrical connection can cause unbalanced voltages and shorten the available life of the motor. Motors need to be de-rated for voltage unbalances as small as 1%.
- Perform three phase-to-phase impedance tests to ascertain the health of the stator winding and rotor bars (should be within 10% of each other).

In addition to the foregoing testing, during major turbine overhauls (HP for cross-compound units), motors rated 2 kV and higher and associated cables should be overvoltage (hi-pot) tested to predict a future life of the insulation system.

> **NOTE:** If a rewind is required, it is recommended that the new winding be manufactured to Class H insulation to improve life expectancy. In coal-fired plants where fly ash abrasion of insulation is a problem, an RTV-like substance can be applied to the end winding surfaces, helping to reduce fly ash abrasion failures. RTV coating of end windings can also be used to mitigate salt contamination and tracking in open-ventilation medium-voltage motors in close proximity to coastal areas.

7.3.4 Internal Inspections

Where the failure of a motor would result in the loss or restriction of generation, the motor should be thoroughly inspected internally and frequently enough to ensure continuous service. At least one motor in each group of motors (boiler feed pump, circulating water pump, induced draft fan, forced draft fan, condensate pump, etc.) should be inspected during major turbine overhauls. When a motor is found to be in poor condition, all other similar motors in the group should be inspected.

A major inspection of a motor should include the following checks:

- Remove the upper end bells and internal dust shields and inspect the stator and rotor as far as practical. Verify that the iron-core ventilation passages are clear of contamination (particularly important in coal-fired plants).

- Check the air gap using a feeler gauge (in four positions, if possible). Maximum allowable eccentricity in both the horizontal and vertical direction is 10%.

$$\% \text{ Eccentricity} = 200\,(R_1 - R_2)/(R_1 + R_2)$$

R1 = largest air gap distance and R2 = smallest air gap distance

- Inspect rotor bars and fan blades for cracks, if practical.
- Check the stator end turn areas for proper blocking and support. Undesirable end turn movement can cause black greasing if oil is in the environment or yellow dusting in a dry condition.
- Check for filler strip and wedge migration.
- Inspect the motor connection box for anomalies. Pay particular attention to the condition of the pigtail leads.
- Check the bearings for wear and replace the oil.
- Check and clean or replace the air or water cooler filters.
- Check coupling alignment. Laser alignment systems have proven to be excellent for verifying motor/coupling alignment.
- Inspect heaters and heater wiring.

When the inspection reveals excessive contamination, deterioration, movement or fouling of the windings, the motor should be disconnected and sent out for cleaning and refurbishment.

Anytime medium voltage motors (2 kV and higher) with shielded cables are disconnected, the single shield ground location should be changed from the switchgear location to the motor connection box. A thorough Electrical Power Research Institute (EPRI) study disclosed that high frequency switching transients during second pole closing can get as high as 5 times voltage, which can stress or fail the turn-to-turn insulation in motor windings. Grounding the cable shield, at the motor end only, reduces switching transients by more than 50%.

Motors rated 2 kV and higher, which are sent out for rewind or cleaning and refurbishment, should be hi-pot tested in the service shop prior to delivery to the station. All motors should be megger, PI, resistance, and impedance tested immediately upon return to the station from a repair facility. The megger, PI, resistance, and impedance testing should be repeated from their respective cubicles when the motors are connected to the feeder cables. All test values should be recorded to permit comparison to measurements in the future.

7.3.5 On-Line and Off-Line Routine Inspections

Based on local environmental conditions, a periodic (at least annually) maintenance routine should be established for the following:

- Cleaning or replacement of air filters and connection box desiccant breathers (if applicable).
- Bearing lubrication system maintenance. Follow manufacturer's recommendations for greasing bearings; overgreasing may cause bearing failure.
- Motor heaters (which are normally energized when the motor is not running) should be equipped with ammeters or LEDs that indicate heater current flow is normal. The heaters and circuitry should be inspected for proper operation during the scheduled routine.

7.3.6 Motor Monitoring and Diagnostics

- Thermographic inspection of leads, frame, and bearings is usually economical for larger motors.
- Motors 1500 HP and larger are normally equipped with embedded resistance temperature devices (RTDs) in their stator windings for monitoring stator temperatures. These devices can be used to drive recorder, DCS systems, and newer digital protective relays. In most plants, they are not being utilized but are always accessible in external connection boxes for measuring stator temperatures if an issue needs to be resolved on the temporary overload capability of the motor where the unit output is limited because of motor loading or to assess the effectiveness of the cooling system or cleanliness of the cooling passages. Generally, the RTDs are slow to respond and not considered effective for severe events, that is, motor stall or locked rotor conditions.
- Current spectrum analysis can be performed routinely for detecting incipient broken rotor bars and/or short-circuiting rings. However, it may be more economical to perform the testing only on motors that exhibit vibration problems or have a history of squirrel-cage rotor problems.
- Either routine or continuous partial discharge monitoring of stator windings is available for motors rated 6 kV and higher. Normally, the cost of these devices can be justified only for motors that are problematic or part of critical plant processes.

7.4 Switchgear Circuit Breaker Maintenance

7.4.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the inspection, care, and maintenance of switchgear circuit breakers.

Proper maintenance of switchgear circuit breakers is essential to obtaining reliable service and performance. Circuit breaker failures are a potential hazard to personnel and other plant equipment and could result in the loss of generation capability.

> **NOTE:** This guideline does not apply to SF_6, oil, and free standing generator or switchyard circuit breakers.

7.4.2 General—Switchgear Circuit Breakers (200 Volts to 15 kV)

Modern switchgear circuit breakers have sensitive mechanisms with critical tolerances and internal forces and loadings that must be maintained in close adjustment to operate properly. Deviation in adjustment could result in improper operation or electrical failure. It is therefore imperative that the manufacturer's recommended settings and instructions are understood and followed. All personnel associated with maintaining circuit breakers and their associated cubicles should be well acquainted with the manufacturer's instructions and recommendations pertaining to both the circuit breakers and the cubicles.

> **NOTE:** Particular care must be exercised when working on breakers that rely on stored energy systems (spring, air, or hydraulic), and appropriate safety practices must be followed.

Because the insulating properties of circuit breakers are adversely affected by the presence of moisture and contamination, all possible precautions must be taken to prevent their intrusion. Spare breakers, and other breakers that need to be stored outside of their designated cubicles, should be stored in suitable heater-equipped enclosures to prevent the intrusion of moisture and contamination. For the safety of plant operators who stand in front of circuit breakers during live rack-in operations, it is essential that the breaker insulation systems prevent the occurrence of insulation flashovers and explosions. Switchgear rooms must be maintained in a clean condition. Cubicle doors and access panels must be kept closed to mitigate moisture and contaminant intrusion. Fans and dampers for positive-pressure switchgear rooms should be properly maintained. Ceiling water leaks should be repaired quickly, and water should not be used to hose down areas near switchgear locations.

No work should be attempted on racked-in energized circuit breakers at any time. All testing and adjustments should be performed with the breaker in the fully racked-out or test position. Additionally, no work should be attempted on the control circuits of racked-in circuit breakers for off-line units, where an inadvertent breaker closure would energize an at-rest generator. The foregoing applies to generator circuit breakers and to unit auxiliary transformer low side breakers (backfeed through the auxiliary transformer) on unit designs where generator bus circuit breakers are not provided.

Adjustment of the main contacts and primary disconnects for source and tie breakers is particularly critical. Current flow through feeder breakers is usually well below the continuous rating. However, it is not uncommon for source and tie breakers to carry close to rated current; consequently, they are much more prone to contact and primary disconnect overheating that can lead to ground and short circuit failures.

7.4.3 Inspection and Testing Frequencies

Switchgear circuit breakers and cubicles should be mechanically inspected and electrically tested at the following intervals or events, and/or following manufacturer's recommendations:

- Periodically, at 2- to 5-year intervals.
- During unit overhauls.
- Before placing new or modified breakers into service.
- Before energizing breakers that have been out of service for over 12 months.
- After an interruption of electrical short circuits, other than a ground fault in a resistance-grounded system.
- After 1000 close-open operations (or less, depending on manufacturer's recommendations) following the last inspection.

7.4.4 Mechanical Inspection

During the mechanical inspection process, the following items should be completed:

- Remove arc-chutes to facilitate the inspection.
- Use vacuum, dry air, or hand wipe to remove dust and other contaminants from the breaker and arc-chutes (do not use air pressure on arc-chutes that contain asbestos).
- Inspect silver-plated parts and replate as required, following manufacturer's recommendations.
- Inspect, adjust, clean, and replace main and arcing contacts as needed. Ensure the contacts have the proper "wipe," alignment, and synchronism and are adjusted as specified by the manufacturer.

  NOTE: A stamp impression of the contacts can be made using very thin tissue paper to ensure that the contact surfaces "make" evenly.

- Clean disconnect or finger clusters, clean control fingers, check spring pressure, and lubricate lightly with approved grease to enhance proper engagement. Check all associated screws and bolts for tightness.

- Perform an overall inspection, looking for loose wiring and connectors or components, heating, cracked insulation, corrosion, and anomalies. Complete repairs as required.
- Check for tracking and corona activity, in particular in those areas close to the interface between insulated and noninsulated conductors.
- Close the breaker manually a number of times and compare variations in mechanical force needed and audible sounds. Variances should be investigated.
- Check for proper operation and condition of auxiliary contacts and relays.
- Vacuum-breaker bottles can leak. To ascertain proper vacuum integrity, some manufacturers recommend carrying out a "pull test" to measure the vacuum by the force required to pull apart the contacts.
- Lubricate moving parts as recommended by the manufacturer or in accordance with experience with a particular type of breaker.
- Prove that the mechanical trip push-button will trip a closed circuit breaker.

7.4.5 Electrical Testing

In general, acceptable measurement values for circuit breaker testing will depend on the model and type of circuit breaker. Experience, manufacturer's information, and review of previous test records will indicate a practical range of acceptable readings for a particular circuit breaker. Corrective action will need to be taken when test measurements are outside of that range. The following electrical testing should be completed to assess the condition of the circuit breaker and to determine if further maintenance is required:

- Before installing the arc-chutes, perform a micro-ohm test of each phase from disconnect stab (or cluster) to disconnect stab (or cluster) with the breaker closed, after manually opening and closing the breaker at least three times. If the breaker is not racked into a test device and is equipped with clusters, the micro-ohm readings should be taken from the mating surfaces that the clusters are installed on and not from the cluster itself. If the readings are acceptable, install the arc-chutes for further testing; otherwise, isolate and correct the problem.
- Perform an overvoltage test of the breaker. All circuit breakers should be tested with a 1000-volt megger. If the megger test results are acceptable, an AC hi-pot (overvoltage) test should be performed on 2 kV and higher voltage-rated breakers. Considering the severe consequence of an insulation breakdown, the low cost for a low capacity 30 kV AC test set, and that breaker insulation failures are easy to repair, the AC hi-pot testing of all medium voltage (2 kV and higher) switchgear circuit breakers is recommended.

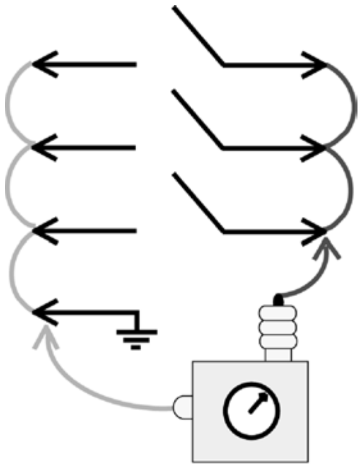


FIGURE 7.1
Open-Pole Insulation Test

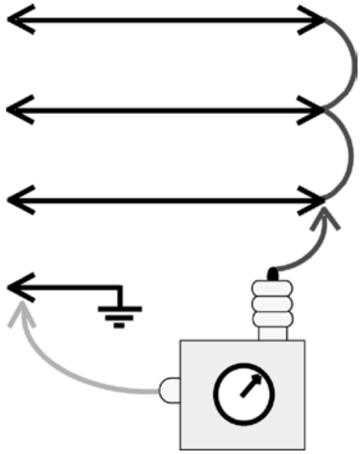


FIGURE 7.2
Phase-to-Ground Insulation Test

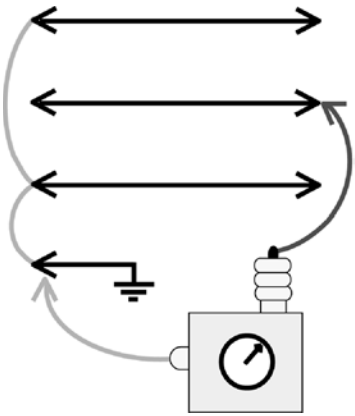


FIGURE 7.3
Phase-to-Phase Insulation Test

The following are the routine AC overvoltage test values for switchgear circuit breakers of various voltage ratings:

- 2.4 to 5 kV breakers 14.25 kV AC
- 7.2 kV breakers 19.5 kV AC
- 13.8 kV breakers 27.0 kV AC

The breaker should be able to hold the test voltage for 1 minute.

As illustrated in Figures 7.1, 7.2, and 7.3, three tests will be required to properly megger or overvoltage stress the circuit breaker:

- Open-pole insulation
- Phase-to-ground insulation
- Phase-to-phase insulation

The following describes each test:

- *Open-pole insulation*: With the breaker open and A, B, and C phases jumpered together on both sides of the circuit breaker, connect the "hot" lead to the movable-contact side, and the test set *return*-lead and breaker frame-ground to the stationary-contact side. Minimum insulation resistance for this test is 3 megohms per rated phase-to-phase kV.
- *Phase-to-ground insulation*: With the breaker closed and all jumpers and leads removed from the stationary side, connect the *return* to the breaker frame-ground to test the phase-to-ground insulation. Minimum insulation resistance for this test is 3 megohms per rated phase-to-phase kV.
- *Phase-to-phase insulation*: With the breaker closed and A and C phases jumpered together, connect the hot lead to B phase and the return and breaker frame-ground to A and C phases to test the phase-to-phase insulation. Minimum insulation resistance for this test is 6 megohms per rated phase-to-phase kV.

Hi-pot leakage currents should be recorded during the foregoing testing and investigated when out of acceptable ranges or when there is a significant unbalance between phases. If the breaker does not pass the open pole megger or hi-pot test, the arc-chutes may require cleaning. Care must be taken when cleaning arc-chutes that contain asbestos, especially if the material is friable. Arc-chutes that do not contain asbestos can normally be glass-bead blasted. Arc interruption by-products can be removed by hand from asbestos containing arc-chutes, with nonmetallic grit sandpaper if care is taken to avoid the asbestos material. Ceramic surfaces can also be wiped clean with an approved solvent.

> **NOTE:** Applicable local regulations must be followed when handling asbestos materials or when performing maintenance activities with equipment containing asbestos or suspected of containing asbestos.

- *Vacuum breakers*: The normal method for testing vacuum-bottle integrity is to overvoltage or hi-pot the bottles. Manufacturer's recommendations, intervals, and precautions should be followed. At a minimum, vacuum-bottle hi-pot tests should be performed at no more than 5-year intervals. The tester should be aware of the possibility of x-ray radiation from vacuum bottles under test.

7.4.6 Operational Tests

Connect the breaker to a test stand and perform the following tests:

- *A 70% of rated-voltage close test*: Failure of the breaker to close may indicate the need for mechanism cleaning, lubrication, and adjustment.
- *A 50% of rated-voltage trip test*: Failure to trip may indicate the need to clean, smooth, lubricate, and adjust the latch mechanism.
- *Full-voltage close and open timing tests*: Using a high-speed cycle counter, measure the close and open time for three consecutive operations. If the average of the three timing tests falls outside the acceptable range, the bearings may need cleaning, lubrication, or replacement.
- Test the trip-free and safety interlocks for proper operation and correct any deficiencies.

7.4.7 Cubicle Inspection

During the cubicle inspection process, the following items should be completed:

- Examine the bottom of the cubicle for parts that may have fallen from the breaker. The bottom of each cubicle should be maintained clean and free of any foreign objects to facilitate the detection of fallen parts.
- Verify that the mechanical safety interlocks and stops are intact.
- Check that the cubicle heaters (where applicable) are functioning properly.
- Verify that the rack-in mechanism is aligned correctly.
- Lubricate racking mechanism (jacking screws and bearings) according to station experience or manufacturer's recommendations. Check brush length of associated motor (when applicable).
- Perform an overall inspection looking for loose wiring or components and anomalies. Complete repairs as required.
- Verify that the shutter mechanism functions properly.
- The primary disconnects should be inspected for signs of overheating, cracked insulation, cleanliness, and misalignment.

NOTE: Normally, the bus side will be energized; hence, the proper safety measures must be followed.

7.4.8 Rack-In Inspection

The following system checks should be completed prior to returning the breaker to service:

- Have the breaker racked into test position, turn the DC on, witness a close-open operation, and verify that the cubicle door status lamps and mechanical semaphores are functioning properly.
- Arrange to have the open breaker racked into operating position and verify proper cell depth and alignment.
- When the foregoing inspection process is satisfactory to the participating electrician or technician, an adhesive label should be attached to the front of the breaker that indicates the date of inspection and the name of the responsible person.

7.4.9 Generator DC Field Breakers

Generator field breakers should be inspected according to the same guidelines as detailed for other switchgear circuit breakers. In addition, particular attention should be given to the mechanical adjustments and condition of the discharge resistor insertion contacts. Ohmic measurements of field breaker discharge resistors should be taken during the inspection process to verify proper values. Considering the importance of generator field breakers, prior to returning racked-out generator field breaker to service, and allowing for possible troubleshooting time, a close-open test should be performed from the control room, with the breaker racked in (without excitation power), to ensure that the breaker is functioning properly.

7.5 Insulation Testing of Electrical Apparatus

7.5.1 Purpose

The purpose of this guideline is to provide suggested criteria and intervals for the insulation testing of electrical apparatus. This guideline is not intended to be a complete procedure on insulation testing, and personnel performing the tests are expected to be familiar with safety and other detailed aspects of high voltage insulation testing. Testing is performed to verify equipment integrity and to provide a measure of confidence that the insulation will prove reliable until the next major outage.

> **NOTE:** Although some overvoltage test currents are below the accepted lethal levels, the stored charge energy in the insulation capacitance can be lethal. The stored charge must be discharged or drained before the device can be considered dead. The charge is stored by dielectric capacitance between the object under test and the surrounding ground. The rule of thumb is, at minimum, to discharge by connecting low resistance from the conductors of concern and ground and maintain the connection for at least 5 times longer than the overvoltage test duration.

7.5.2 Apparatus 440 Volts and Higher

To determine the integrity of 440 and higher voltage AC apparatus, 1000-volt megger testing should be performed periodically. The frequency of testing should be determined by site-specific environmental conditions and experience with the particular equipment. In general, the maximum interval between tests should not exceed 3 years.

> **NOTE:** For apparatus 4 kV and higher a 2500-volt megger test set can be used, and for apparatus 5 kV and higher a 5000-volt megger can be used. However, experience indicates that for most practical purposes, a 1000-volt instrument provides an accurate enough measurement for apparatus of all voltage ratings.

The following presents a minimum megohm criterion based on operating conditions for all AC electrical apparatus 460 volts and higher that should be met before energizing equipment. The following test criterion assumes the temperature of the apparatus under test is 25°C. This approach will be conservative for measurements carried out at temperatures higher than 25°C.

7.5.3 Normal Routine Maintenance

The minimum megohms for testing all three phases at the same time is 3 megohms per rated φ-φ kV; for example, a 4 kV motor should have at least 12 megohms to ground, and a 460 volt motor should have at least 1.4 megohms to ground. Three (3) megohms per kV roughly translates to the IEEE recommendation for large AC three-phase motors (1 megohm per kV plus 1 megohm at 40°C) at ambient temperatures and, in the interest of simplicity, is suggested for all electrical apparatus.

This criterion assumes that all three phases are being tested simultaneously. When one phase at a time is tested (cables or breakers) with the other two phases grounded, the minimum megohms should be multiplied by 3. For example, an A-phase 4 kV cable should have a least 9 megohms to ground per rated φ-φ kV, or 36 megohms total to ground when tested isolated from the other, grounded, phases.

> **NOTE:** IEEE Standard 43 (Testing Insulation Resistance of Rotating Machinery) indicates that when meggering one phase at a time (with the other two grounded), the measured value should be multiplied by 2, unless guards are used, in which case the readings should be multiplied by 3. This guideline opted for the more conservative approach of multiplying by 3 in both cases.

This criterion also applies to a complete system or parts of a system at the apparatus level. In other words, it is acceptable to isolate apparatus units to meet the requirement individually; that is, a motor can be isolated from the cables, and if the cables and motor meet the requirement separately, they can be reconnected and energized.

Electrical apparatus that do not meet the aforementioned minimum megohm requirements should be cleaned, dried out, or refurbished prior to energizing. On some apparatus, a 10 minute PI test will help to determine if the low readings are due to moisture or other contamination. The PI test divides the 10 minute measurement by the 1 minute measurement. Because the test voltage is DC, the capacitive charging current decreases as the test duration continues, resulting in higher megohm values. In general, a PI value of 2.0 is considered good for most cases unless the apparatus has a history of lower PI values.

7.5.4 Avoiding a Forced Outage or Load Restriction

Some plants are willing to take an economic risk and use a different minimum megohm value to avoid a forced outage of the unit or load restriction of 2 megohms per rated φ-φ kV (with a minimum of 1 megohm regardless of voltage); that is, a 4 kV motor should have at least 8 megohms, and a 440 volt motor should have at least 1 megohm to ground.

This criterion assumes that all three phases are being tested simultaneously. Where one phase at a time is tested (cables or breakers) with the other two phases grounded, the minimum megohms should be multiplied by 3. For example, an A-phase 4 kV cable should have a least 6 megohms to ground per rated φ-φ kV, or 24 megohms total when it is isolated from the other grounded phases.

This criterion also applies to a complete system or parts of a system at the apparatus level. In other words, it is acceptable to isolate apparatus units to meet the requirement individually; that is, a motor can be isolated from the cables, and if the cables and motor meet the requirement separately, they can be reconnected and energized.

Electrical apparatus that do not meet the aforementioned minimum megohm requirements should be cleaned, dried out, or refurbished prior to energizing. On some apparatus, a 10 minute PI test will help to determine if the low readings are due to moisture or other contamination.

7.5.5 DC High Potential Testing

General: Generators and motors 2 kV and higher voltage should be routine overvoltage tested during major turbine overhaul outages (HP turbine for cross-compound units). Normally, for convenience, cables that feed motors are included in the overvoltage test (motor routine values not considered high enough to unduly stress cable insulation). Otherwise, the routine overvoltage testing of cables is not recommended.

It is impossible to tell before testing if the apparatus insulation will fail during the overvoltage (hi-pot) test. Accordingly, time to procure material and repair or replace equipment must be provided when scheduling the test. However, the routine test values provided for motors and generators in this document are the minimum (125% instead of 150%) recommended by IEEE. These values are considered searching enough to provide a measure of confidence that the insulation will not fail before the next major outage and yet do not stress the insulation system enough to force an undesirable premature failure. The higher test values provided for new or refurbished apparatus assumes that the manufacturer or repair agency is financially responsible for a test failure (under warranty) and should not be performed if that is not the case.

A 1000-volt megger polarization test of 2.0 or greater would normally be required before proceeding with a hi-pot test on generator and motor stator windings. The PI (ratio of the 10 minute to the 1 minute insulation resistance readings) is an indication of the fitness of the winding for the overvoltage test. A low PI (less than 2.0) may indicate that cleaning, dry-out or repair is required before the hi-pot can be performed. However, some insulation systems in good condition will not provide a PI of 2.0 or greater. Where that is the case, and the PI measurement is in agreement with historical measurements for the particular insulation system, proceed with the overvoltage testing.

A minimum insulation resistance using a 1000-volt megger of 9 megohms per rated φ-φ kV is required when one phase is tested in isolation from the other phases (preferred for generators and cables) and 3 megohms per rated φ-φ kV when all three phases are tested together (motors). Apparatus with megger readings below minimum should not be hi-pot tested. Apparatus not meeting the recommended minimum megohm values should be dried out, cleaned, or refurbished prior to hi-pot testing.

> **NOTE:** Overvoltage testing should be performed only by technicians or engineers who are familiar with the required safety and test procedures and are properly trained to perform the testing. Due to the high cost of test failures, the overvoltage testing of 10 MVA and higher generators should be witnessed by supervisors or engineers who also have experience in overvoltage testing.

Motors and generators are normally tested at the *start of the outage* to allow time to complete any required repairs during the outage window. Additionally, it is desirable to perform the testing while the apparatus is in a dry condition (before disassembly or in a cold standby condition). Generators are normally tested completely assembled and under hydrogen pressure (where applicable). On generators equipped with inner water-cooled stator coils, the water is normally evacuated by pulling a vacuum to facilitate megger testing for acceptable PI and minimum insulation resistance values before proceeding with the overvoltage testing.

As illustrated in Figure 7.4, wye-connected generators are normally disconnected at the output and neutral ends. Each end of the winding is connected

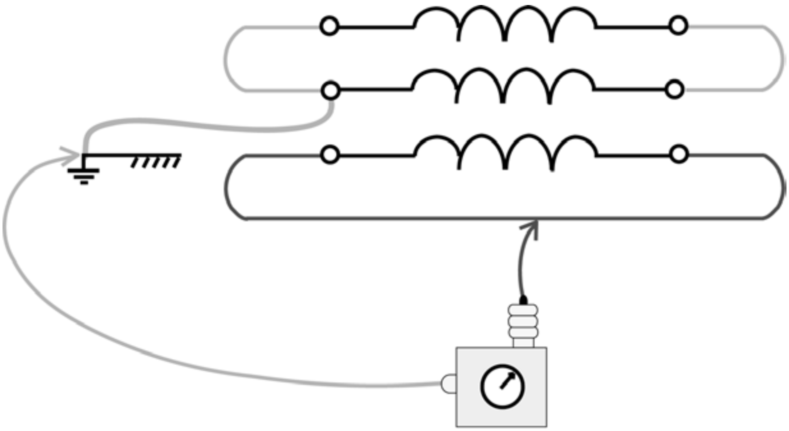


FIGURE 7.4
Generator DC Hi-Pot Test

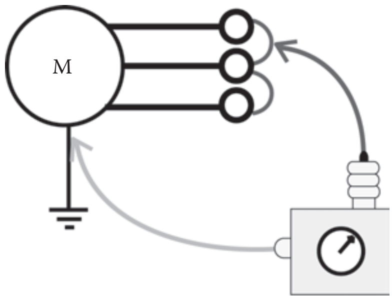


FIGURE 7.5
Motor DC Hi-Pot Test

together with copper bonding wire, and each phase is individually tested to ground with the other two phases grounded. All three phases for motors without neutral leads brought up to the termination box are normally tested simultaneously to ground. Motors and associated cables are usually tested together from the switchgear cubicle with all three phases bonded together, as shown in Figure 7.5. Cables should be separated from the motor only when the readings of the combined motor-cable system are not satisfactory.

Generators are normally tested with a rate of voltage rise or steps of approximately 2 kV DC and motors with a rate of rise of approximately 1 kV DC. The operator should record the voltage and current readings (after stabilization) for each step. The DC current should be closely monitored and if the current starts to rise in an uncharacteristic manner, indicating that insulation break down is imminent, the test should be aborted by steadily reducing the voltage to zero. A successful test is concluded when the recommended voltage value is reached and the current is stable for 1 minute. At the conclusion of the test, the voltage should be steadily reduced to zero to avoid sudden changes and the development of potentially damaging transient voltages.

The following calculated test values are based on nameplate rated kV.

7.5.6 Generator and Motor Stator Winding Test Values

- Field acceptance test for new stator winding
  2 × rated φ-φ kV + 1 kV x 1.7 × .85 [kV DC]
  Examples (13.8 kV generator = 41 kV DC)
  (4 kV motor = 13 kV DC)
- First-year test (under warranty)
  Rated φ-φ kV × 1.5 × 1.7 [kV DC]
  Examples (13.8 kV generator = 35 kV DC)
  (4 kV motor = 10 kV DC)
- Routine test
  Rated φ-φ kV × 1.25 × 1.7 [kV DC]
  Examples (13.8 kV generator = 29 kV DC)
  (4 kV motor = 8.5 kV DC)

7.5.7 Generator Rotor Field Test Values

- Field acceptance of new winding insulation
  10 × rated voltage × 1.7 × .8 [kV DC]
  Example (500 VDC field = 6.8 kV DC)
- First-year test (under warranty)
  10 × rated voltage × 1.7 × .6 [kV DC] (if under warranty)
  Example (500 VDC field = 5 kV DC)
- Routine test (during overhauls)
  One thousand (1000) volt megger test only: acceptable results will be a minimum PI of 2.0 and a minimum insulation resistance of 0.1 × rated voltage in megohms. A 500 VDC field should have a minimum megohms of 50 to meet this requirement. Normally, several hours of cleaning the insulation material beneath the collector rings are required to remove oil and carbon brush contamination before successful readings can be obtained.
- To avoid a forced outage
  4 megohms per kV
  Example (500 VDC field = 2 megohms)

7.5.8 Generator Neutral Buses or Cables

Generator neutral bus and/or cable to the grounding transformer should be disconnected at each end and routinely hi-pot tested during overhauls at the routine value for the generator stator.

7.5.9 Cable 5 kV and Higher

Voltage cables 5 kV and higher should *not* be routine tested at cable hi-pot values during overhauls unless the integrity of the cable is suspect. Because of high test voltages and the limitations of the switchgear and associated CTs, the cables must be disconnected at both ends to perform a full value routine level hi-pot test.

New cables should be hi-pot or partial discharge tested before and after installation to fix warranty responsibility and to ensure that the cables were not damaged during shipment or installation.

The hi-pot values for cable testing are dependent on the type of insulation material, insulation thickness, and the voltage class. The variations are too numerous to cover in this guideline. Normally, the after installation test is performed at 80% of the factory test value and routine tests are performed at 60% of the factory value. Please refer to the Insulated Cable Engineer Association (ICEA), Association of Edison Illuminating Companies (AEIC), Institute of Electrical and Electronic Engineers (IEEE), Electrical Power Research Institute (EPRI), and other appropriate standards for test values and details before hi-pot testing cables.

Where the cable manufacturer does not recommend hi-pot testing, partial discharge testing should be performed instead. Cable insulation systems are chemically complex and represent many variations or families within the same generic type, that is, CLP and EPR (ethylene propylene rubber). Cable hi-pot values may shorten the life of some cable insulation systems by causing molecular changes and/or voids in the insulation. Motor hi-pot levels are significantly lower than cable hi-pot values and consequently are considered safe for all cable insulation systems.

7.6 Bus and Motor Control Center (MCC) Maintenance

7.6.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the inspection, care, and electrical maintenance of buses and MCCs. This guideline is intended to include all major electrical buses, that is, generator isolated phase and neutral buses, transformer outdoor buses, auxiliary power switchgear buses, MCC buses, battery distribution buses, and critical control power buses.

7.6.2 Bus Inspections

Where outages permit, electrical buses should be inspected on 2- to 5-year intervals. Generator and transformer isolated phase buses are normally inspected during unit overhauls.

The buses should be checked for moisture, contamination, overheating, excessive oxidization, discoloration, electrical tracking, flexible shunt or braid erosion, bird nests, rodents, proper sealing, and any other anomalies. The primary disconnects for each position (bus and load side) should be included in the inspection for switchgear buses. Deficiencies should be corrected during the inspection process. Accessible bus insulators should be cleaned and bus bolts checked for tightness. The bolts should be torqued to values that are compatible with the softest material involved and not necessarily to the value recommended for the particular bolt. Flexible braids and shunts that are eroded in a manner that would reduce their current carrying capability should be replaced. Where necessary, silver-mating surfaces should be replated. Aluminum oxide can cause high resistance connections, and treatment with an approved de-oxide grease is necessary to prevent failures of aluminum connections. The oxide can form very rapidly, and the grease should be applied immediately after cleaning. Normally, the mating surface is brushed or file carded after the grease is applied to ensure that any oxide formations that may have formed during the process are broken loose.

7.6.3 Bus Testing

The buses should be megger tested during the inspection or overhaul process. The minimum megohms for a single-phase test (one phase at a time) is 9 megohms per rated phase-to-phase kV; that is, each phase of a 4 kV bus should have at least 36 megohms to ground with the other two phases grounded.

In addition to megger testing, switchgear and MCC buses should be micro-ohm tested during the bus inspection to prove the integrity of the associated bus connections and breaker and bucket primary disconnects. This can be accomplished by grounding all three phases at the source and measuring the micro-ohms from the source to each phase in each breaker cubicle or MCC position. The micro-ohms for phases located within the same position or cubicle should be within 5% of each other, and the measurements should increase slightly for positions that are farther from the source.

Additionally, to take advantage of the accessibility (breakers out of the cubicles), the switchgear and loads should be megger, resistance, and impedance tested during the bus inspection and testing.

7.6.4 MCC Position Inspections

At 2- to 5-year intervals, MCC positions should be physically inspected. The MCC positions should be inspected for loose components, contamination, moisture, overheating, and connection tightness. The positions should be cleaned and the main contacts cleaned and dressed as required. Anomalies should be corrected during the inspection process.

> **NOTE:** The MCC position may be energized at the power disconnect device (molded case breaker or fused disconnect). No maintenance should be attempted on the energized portion of the MCC position.

7.6.5 MCC Position Testing

MCC loads should be megger, resistance, and impedance tested during the position inspection process. Additionally, motor operated valves and dampers should be electrically operated through their range (where possible) to ensure proper operation.

7.7 Protective Relay Testing

7.7.1 Purpose

The purpose of this guideline is to provide suggested procedures and intervals for the testing of protective relaying. Proper relay operation is essential to mitigate equipment damage and hazards to personnel, and to reduce the duration of forced outages.

7.7.2 General

Routine tests on protective relays and associated equipment are normally made in accordance with standards, test manuals, and manufacturer's instructions. Only properly trained engineers/technicians should be allowed to maintain protective relay systems. All testing activities should be coordinated with control room personnel.

7.7.3 Testing Schedule (440 Volts to 765 kV)

Protective relay routine testing is normally performed at 2- to 5-year intervals or plant overhaul outages, but should not exceed 6 years in duration.

7.7.4 Relay Routine Tests

When possible, the following steps should be completed during the routine testing:

- Where possible, megger and inspect CTs and PTs and associated wiring. Electronic relays should be isolated during the megger test.

  NOTE: Care must be taken to ensure that the CTs under test are completely de-energized. CTs that are wrapped around an energized bus or connection, even though there is no current going through the bus or connection, must be treated as energized.

- Perform a thorough mechanical check of the protective relays, switches, wiring terminals, and auxiliary relays and timers. The inspection should include looking for metal chips or filings, or other foreign objects in the area of the magnetic gaps. Contacts should be cleaned as required. Dirt and contamination should be removed with a soft brush, or by low-pressure dry air or vacuum.
- Complete an electrical calibration of the protective relay (normally with the relay in its case) using in-service taps and adjustments to ensure that it will operate properly (within 5%) over the intended range.
- Prove that the tripping and alarm circuits will perform their intended operations.

  NOTE: High and medium voltage circuit breakers, fuel trips, and turbine steam valve operations should be kept to the minimum required during each relay routine and trip test. One trip operation for each apparatus function is required; subsequent tests from different (86) or direct trip relays should be proven by drawing light bulb current on the particular trip wire or open trip cut-out switch instead of actually retripping the equipment.

- Make a final in-service test to determine that the protective group is being supplied the proper currents and potentials as required for the various elements after the relay group is returned to service.

7.7.5 Primary Overall Test of Current Transformers (CTs)

Primary injection tests from each phase and CT group, with all secondary current devices included, should be performed to ensure proper operating values and performance whenever the following conditions are met:

- During the initial installation or replacement of CTs.
- Anytime a CT's ratio is changed or there is a major wiring change in the secondary circuit.
- If there is any reason to suspect faulty operation of the CTs.

NOTE: Secondary tests (light bulb current) are acceptable for proving minor changes to the secondary wiring and for proving major changes where primary injection tests are not practical because the CTs are not accessible.

7.7.6 Documentation

Each station should maintain files on the protection philosophies, calculations, relay settings, and coordination of protective relaying for low voltage switchgear-fed loads and higher voltage electrical systems.

Relay data cards should be maintained at the relay. The cards should show the date of the last routine test and the name of the responsible technician or engineer. The card should also indicate the name of the circuit, instrument transformer ratios, and the relay settings in secondary values. Where a separate relay is provided for each phase, the data card should be attached to the A-phase relay only. The relay settings for multifunction digital relays do not need to be shown on the relay card.

7.7.7 Multifunction Digital Relay Concerns

With multifunction digital relays, there are two areas of concern:

- When testing digital relays, there can be element or function interference, and it may be desirable to temporarily take elements or functions out of service to facilitate the testing. In this case, documented procedures should be established; that is, check sum numbers, software comparison routines, and so forth, to ensure that all desired alarming and tripping functions are placed back into service following the testing.
- The relay settings provided should be presented in a manner where the commissioning and routine testing engineer or technician has absolutely no doubt about the intentions of the protection engineer responsible for issuing the settings. The information must be presented in way that is not subject to interpretation.

7.8 Battery Inspection and Maintenance

7.8.1 Purpose

The purpose of this guideline is to provide suggested procedures and intervals for the maintenance of plant battery banks. Batteries must be maintained correctly to prevent unnecessary outages and to ensure that backup emergency power is available for the turbine emergency DC oil pumps and other important loads. Proper battery maintenance is vital to ensure that control and shutdown systems function properly to mitigate damage to equipment and risk to plant personnel. This guideline covers lead acid batteries in detail; for other types of batteries, follow manufacturer's recommendations.

7.8.2 General

Approved maintenance and safety procedures should be in place before performing any work on station batteries. Routine tests on batteries and associated equipment are normally made in accordance with standards and procedures outlined in manufacturer's instructions and should also take into account any specific requirements or code of practices in the jurisdictional location where the batteries are installed. Additional references that can be consulted are IEEE Standard 450 "Recommended Practice for Maintenance, Testing, and Replacement of Large Load Storage Batteries for Generating Stations" and EPRI's *Power Plant Electrical Reference Series,* volume 9.

Room temperature can impact battery performance and, in some cases, may alter the set point of the charger voltage. When taking measurements, always record the temperature of the room where the battery bank is located. Batteries normally have reduced capacity at lower temperatures because the electrolyte resistance increases. At higher temperatures, they have increased capacity but lower life expectancy. EPRI recommends a battery room temperature range between 60°F and 90°F, with an average temperature of 77°F.

Batteries are to be kept clean and dry on the outside, and all necessary precautions should be taken to prevent the intrusion of foreign matter into the cells. All cell connections should be kept tight and free from corrosion.

All battery areas should be adequately ventilated, and the air should exhaust to the outside and not circulated to other indoor spaces. A concentration equal to or greater than 4% hydrogen is considered dangerous. Care should be taken to prevent pockets of hydrogen near the ceiling. If the ventilation system is out of service and work needs to be performed in the battery room, the area should be treated as hazardous, for both its possible lack of oxygen and its possible explosive nature. The room should be properly ventilated before proceeding with any work.

Only distilled or approved demineralized water shall be added to maintain the electrolyte level as near as practical to the marked liquid level lines. Do not fill above the upper or maximum level lines. All water intended for battery maintenance should be tested for acceptable purity before use. Acid should never be added to, or removed from, a cell without specific instructions from the manufacturer.

Appropriately trained and qualified station personnel would normally perform weekly, monthly, quarterly, and annual maintenance inspections. All measurements should be properly documented, and any discrepancies found should be reported to the appropriate supervisor.

The voltage chosen as the float voltage has an effect on the stored ampere-hour capacity of the battery. In general, as the float voltage is reduced, so is the stored ampere-hour capacity. Overall terminal voltages of batteries will vary depending on the number of cells. The typical number of cells for generating station applications is 60.

7.8.3 Floating Charges

There are various types of batteries; the guideline covers some of the more popular types. All should be maintained, operated, and set up in accordance with standards and procedures outlined in manufacturer's instructions. The guidance presented below provides data that are generally acceptable for lead acid batteries.

- *Lead antimony* batteries are normally to be kept on floating charge at an average voltage of 2.19 volts per cell but not more than 2.23 or less than 2.15 volts per cell, per EPRI guidelines (except as specified differently by the manufacturer).
- *Lead calcium* batteries are normally to be kept on floating charge at an average voltage of 2.21 volts per cell but not more than 2.25 or less than 2.17 volts per cell, per EPRI guidelines (except as specified differently by the manufacturer).

7.8.4 Inspection Schedules

The following presents the recommended intervals for inspecting battery banks:

- *Daily*: Operations should perform visual inspections of all battery banks, chargers, and associated ground detectors during each shift. Maintenance orders should be generated for any discrepancies found. This may be relaxed if appropriate and reliable alarm systems are in place.
- *Weekly*: Station electricians or technicians should visually inspect the chargers and battery banks once a week and take an overall voltage reading with a calibrated voltmeter. Anomalies found should be corrected during the inspection process.
- *Monthly*: Station electricians or technicians should inspect the chargers and batteries, check the electrolyte levels, and add distilled water as needed. Discrepancies found should be corrected during the inspection process.
- *Quarterly*: Once a quarter, the station electricians should do the following:
    - Measure the specific gravity of each cell, starting at number 1, and record the reading.

- Raise battery-charging voltage as high as circuit conditions will permit but not to exceed 2.33 volts per cell for a *check charge.* Allow 10 minutes for the voltage to stabilize and record the following readings:
  - Overall voltage at the beginning of the readings.
  - Individual cell readings, starting at cell number 1.
  - Overall voltage at the end of the readings.
    - If the lowest of the individual *antimony* cell voltage is within 0.05 volts of the average of all cells and the cells are gassing freely, the check charge is complete and the charger should be returned to normal floating charge.
    - If the lowest of the individual *calcium* cell voltage is within 0.20 volts of the average of all cells and the cells are gassing freely, the check charge is complete and the charger should be returned to normal floating charge.
    - If one or more antimony cells indicate 0.05 volts below the average of all cells, or if one or more calcium cells indicate 0.20 volts below the average of all cells, the check charge is to be carried on to an *equalizing* charge. The equalizing charge should be set to 2.33 volts per cell, times the number of cells, and held for a period of 8 hours.
    - If the equalize charge does not bring the individual cell voltages to acceptable limits, consult with the manufacturer. If the cell voltages are within acceptable limits, return the charger to normal floating charge.

- *Annually*: A thorough examination of the battery intercell connections should be performed. Any connection with oxidation or corrosion should be cleaned using the approved cleaning methods given by the battery manufacturer. Interconnection bolts should be checked for proper tightness using approved insulated wrenches. Connections should be tightened to manufacturer's recommended torque specifications using a torque wrench with the appropriate insulation and scale.
  - To test that the batteries still have an acceptable ampere-hour capacity, load discharge tests should be performed during convenient outages using either an appropriate load bank or the turbine emergency DC oil pump load. The duration of the test should be long enough to prove that the batteries have sufficient capacity to prevent damage to turbine/generator bearings during coast-down conditions. A reasonably high discharge rate should be applied to the batteries with the charger switched off *(this discharge, at a minimum, should correspond to the actual load*

expected during an emergency condition, and care should be taken not to exceed the minimum voltage values specified by the battery manufacturer). The actual battery discharge voltage/time characteristic should be compared with that obtained from manufacturer for the same discharge conditions. Any deviation from the curves should be discussed with the manufacturer. The test discharge rate used must be within the specified battery/equipment limits and properly account for temperature values.

- Impedance testing can also be performed if the manufacturer recommends it. A test instrument designed for that purpose should be used.

7.8.5 Safety Precautions

Extreme care must be exercised when performing maintenance on batteries, as they contain either acid or caustic solutions. Before working on batteries, note the location of the nearest eyewash station and safety shower. The following recommendations are provided to minimize hazards to personnel.

- Wear approved protective clothing, rubber gloves, and eye protection when adding liquid to a battery or performing any other activity where there is a possibility of coming into contact with cell electrolyte.
- If acid or caustic materials or solutions contact the eyes or skin, flush with a copious amount of water and seek first aid. Provide in the battery room, or have at hand, suitable eyewash and acid splash dilution facilities that are regularly inspected.
- Exercise care when handling acid or caustic materials and solutions. If spillage occurs, it should be cleaned up immediately. Neutralizing material should be available at the battery room to neutralize any spilled active material. Usually, one pound of baking soda is mixed with one gallon of water to create a suitable neutralizing mixture.
- Smoking, open flames, or heat that could cause the ignition of hydrogen gas is generally prohibited in a battery room. Activities that either may or can cause flames, sparks, or heat should be prohibited unless a competent or qualified person has performed a risk assessment and all of the recommendations of the assessment have been applied. Approved eye protection should be worn when performing any activity that could cause a battery cell to explode.
- Care must be taken not to use materials that may generate static electricity arcing, for example, polythene plastic sheeting.
- When working in a battery room, ensure that the exit from the battery room remains unblocked and unlocked and that all doors have panic bolts on the inside. Doors should be locked when no work is being carried out in a battery room, to prevent unauthorized access.

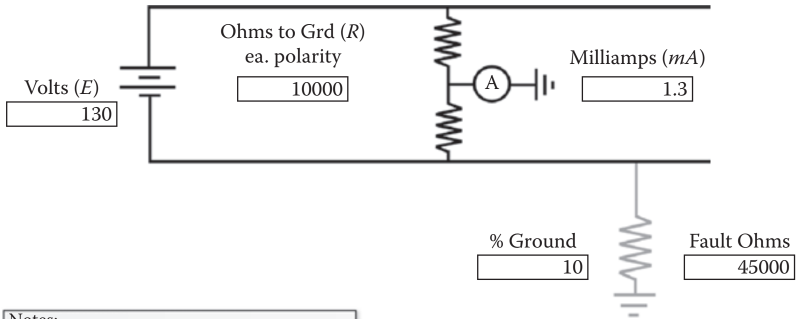
- Use of noninsulated metallic tools on or around the exposed battery terminals or intercell connections is prohibited.
- Use of oil, solvent, detergent, or ammonia solution on or around the battery cases is prohibited. These solutions may cause permanent damage to the special high-impact plastic case materials.
- Be careful when carrying metallic articles, for example, watches, jewelry, pens, spectacle frames, or rulers, when working on batteries. All metallic items not required for performing the assigned activity should not be taken into the battery room.

7.8.6 Operation and Troubleshooting

- *Low voltage*: Critical protective relay DC circuit voltage levels should be monitored to ensure that the protection can operate properly. Whenever the DC voltage level is at or below 95% of nominal, plant operators, electricians, and technicians should immediately investigate and resolve the problem or remove the protected equipment from service.
- *High voltage*: Whenever the DC voltage level is found to be above the equalize level 110% of nominal (battery charger malfunction), plant operators, electricians, and technicians should immediately investigate and resolve the problem or remove the protected equipment from service.
- *DC grounds*: Critical protective relay DC circuits should be monitored for grounds to ensure that the protection can operate properly. Normally, ground detectors are set to alarm for a 10% ground. At the first indication of a DC ground, plant operators, electricians, and technicians should immediately investigate and resolve the problem or remove the protected equipment from service.

NOTE: It is not permissible to temporarily interrupt the DC to in-service circuit breakers or critical protective relays unless protection engineering determines that adequate backup protection is in service. Critical protective relays are those that are associated with the high voltage bulk power systems, sub-transmission systems, or main unit generators.

Figure 7.6 presents a calculation for determining the DC ground fault resistance in a typical plant battery ground detector scheme. The figure shows two 10,000 ohm resistors that are connected to each polarity of a 130 volt DC system with the common point connected to ground. As shown, in this case, a 10% ground or alarm actuation point is equal to 45,000 ohms to ground.



Notes:
The calculation is useful for determining the alarm point sensitivity for ground faults. If the detector is too sensitive (ground goes away when the sun comes out), the % pickup can be increased or the detector ohms to ground for each polarity can be reduced.

$$Milliamps\ (mA) = \left(\frac{E}{R}\right) \times \left(\frac{\%\ Ground}{100}\right) \times 1000$$

$$Fault\ Ohms = \frac{0.5E\ ((100 - \%\ Ground)/100)}{mA/1000}$$

FIGURE 7.6
DC Ground Fault Ohms

7.9 Personnel Safety Grounds

7.9.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the application, inspection, care, and maintenance of personnel safety grounds.

This guideline applies to all switchgear (draw-out circuit breakers and contactors) fed electrical systems (480 volts and higher). Typical short circuit currents for low voltage 480 volt switchgear systems are in the same range as the higher medium voltage systems (15,000 to 45,000 amps). This guideline does not apply to low voltage systems and loads that are fed from MCCs or distribution panels. The short circuit currents for these systems are usually lower than those available from switchgear-fed auxiliary power buses and feeders.

7.9.2 General

Personal grounds are applied on all three phases for the following reasons:

- Prevents the development of dangerous, even lethal, induced or inadvertent energizing voltages where the employee or contractor is working.
- Provides a short circuit current path that will result in the automatic tripping of any breakers involved in inadvertent or accidental switching energizations by in-service protective relays.

To accomplish this, portable grounds and grounding devices must be able to do the following:

- Mechanically withstand the short circuit electromechanical forces developed at the particular location.
- Have the thermal capacity to carry the short circuit current at the specific location. The calculation for determining the amount of time the safety grounding cable can carry short circuit current before it fuses open was discussed in Chapter 5.

Portable personal grounds are often made from flexible 2/0 conductors and clamps that have been approved for this purpose by vendor short circuit testing. Conductors of a size equal to 2/0 will fuse open in approximately 18 cycles with short circuit values of around 35,000 amps. To be effective, the fuse time of the personal grounds has to be longer than the protective relay clearing times (relay plus circuit breaker).

Personnel grounds must be connected directly to the station ground grid, where available, to reduce the circuit impedance and associated voltage rise during short circuit conditions. Additionally, all connections must be secure to reduce the contact resistance and corresponding heating of the connections and to ensure that the grounds can mechanically withstand the electromechanical forces when carrying short circuit currents.

Personal grounds should be located in between work locations and any possible sources of inadvertent energization. Where there is the possibility of induced voltages from neighboring energized conductors or circuits, the grounds must be located in the general proximity of the employee to prevent a voltage rise at that location from short circuit currents flowing in the adjacent energized circuits. It is not unusual for cables to share cable tray and duct banks with other energized circuits. For example, if motor cables are within 1 foot of another circuit and parallels the circuit for 900 feet, a 35,000 ampere ground or double line to ground fault in the neighboring circuit can induce 1 to 5 kV (depending on how the fault current returns to the source) into the out-of-service motor cables for the duration of the fault. Consequently, the end of the conductor that the worker is touching (motor end) needs to be grounded to prevent a hazardous voltage rise.

7.9.3 Special Grounding Considerations

The following locations in generating stations usually require special consideration for safety grounding:

- *Low voltage side of generator step-up transformers*: In this case, applying grounds on the low voltage side of the generator step-up transformer will usually not protect the worker from an inadvertent high voltage side energization even if the grounds are located in between the worker and the step-up transformer. The short circuit currents are normally too high for personal grounds; the clamps will not be able to withstand the electromechanical forces and the grounding cables will fuse open almost instantaneously from the high current values. Accordingly, high voltage side grounds must be applied to protect workers on the low voltage side of generator step up transformers. Grounds should also be applied on the low voltage side to protect workers from an inadvertent energization from the unit auxiliary transformer.

- *Switchgear buses*: The protective relaying fault clearing times for switchgear buses often exceeds the thermal capability of the personal grounds. Double grounds or large conductor sizes could be applied to increase the capability of the personal grounds, or a manufacturer's grounding device could be used to ground the bus.
- *Motor or feeder cables***:** Where motor or feeder cables share duct banks or cable trays with other energized or in-service feeders, there is concern about induced voltages from the neighboring circuits. If one of the adjacent circuits develops a ground fault or double line to ground fault, the corresponding high currents can produce a strong magnetic flux that links with the de-energized motor or feeder cables. This flux can easily induce voltages into the cables in the range of 1.0 to 5.0 kV, depending on the magnitude of the current, the distance from the motor or feeder cables to the adjacent circuit, the distance of parallel, and the path of the return short circuit current. Grounding the switchgear end aggravates this condition, as the full amount of induced voltage is referenced to ground at the other end. Grounding only the motor end prevents the worker from exposure to induced voltages at that end but not at the switchgear end. A switchgear-grounding device could be used for work at the switchgear end. For work at the motor end, the preferred method is to *not* ground the switchgear end of the cables. The cables can be disconnected, using properly rated and approved medium voltage gloves (as if it was energized), and personal grounds can be applied to the cables at the motor end immediately after they are disconnected. A reverse procedure can be used to reconnect the cables.

The following list provides induced voltages per 100 feet of parallel, with an adjacent energized circuit at various 60 Hz short circuit levels. It is assumed that the energized circuit is within 1 foot of the conductors where work is to be performed and the return path for the short circuit current is 100 feet away. If the circuit separation is increased to 10 feet, or if the short circuit return path is reduced to 10 feet, the induced voltages will be reduced by one-half. Conversely, if the circuit separation is reduced to 0.1 feet, or if the short circuit return path is increased to 1000 feet, the induced voltages will increase by a factor of 150%.

- 50,000 amps = 530 volts
- 40,000 amps = 424 volts
- 30,000 amps = 318 volts
- 20,000 amps = 212 volts
- 10,000 amps = 106 volts
- 5000 amps = 53 volts

7.9.4 Maintenance

- *Personal grounds*: Personal grounds should be inspected at 2-year intervals. Particular attention should be given to the clamps and terminations on each end of the cable. Cable clamping bolts should be checked for proper torque.
- *Switchgear grounding devices*: Grounding devices should be inspected every 2 years. Primary disconnect finger clusters should be inspected for proper spring tension, all mating surfaces should be inspected for acceptable silver plating, and all bolts involved in current carrying connections should be checked for proper torque values. Proper alignment of the poles and carriage should also be verified to ensure that racking in the grounding device will not damage the cubicle primary disconnects or racking mechanism.
- *Switchgear ground and test devices*: Ground and test devices should be inspected at 2-year intervals. In addition to the maintenance items delineated for grounding devices, ground and test devices should be thoroughly cleaned because approximately one-half of the device becomes energized under normal use.
- *Ground disconnects*: Ground disconnects used for personnel safety should be inspected on 2- to 3-year intervals. Disconnects should be inspected for proper spring tension, all mating surfaces should be inspected for acceptable silver plating (particular attention should be given to hinged areas), and all bolts involved in current carrying connections should be checked for proper torque values. Proper alignment and engagement of the poles should also be verified during this inspection.

7.9.5 Electrical Testing

- *Personal grounds*: During the inspection process, personal grounds should be micro-ohm tested to verify proper current carrying capability. A small amount of increased resistance during fault conditions will force a premature failure of the personal ground. For example, an increased resistance of 1.0 milliohms can cause an extra 100 kW of heating during fault conditions. The micro-ohm readings should be documented and compared to prior readings and other personal grounds for reasonableness. Differences should be investigated and resolved.

- *Switchgear grounding devices*: Grounding devices should be micro-ohm tested, during the inspection process, to verify proper current carrying capability. The micro-ohm readings should be documented and compared to prior readings for reasonableness. Differences should be investigated and resolved.
- *Switchgear ground and test devices*: In addition to micro-ohm tests as specified for switchgear grounding devices, ground and test devices should also be meggered and hi-pot tested during the inspection process.
- *Ground disconnects*: During the inspection process, ground disconnects should be micro-ohm tested to verify proper current carrying capability. The micro-ohm readings should be documented and compared to prior readings for reasonableness. Differences should be investigated and resolved.

7.10 Generator Automatic Voltage Regulators and Power System Stabilizers

7.10.1 Purpose

The purpose of this guideline is to provide suggested procedures and schedules for the testing, inspection, care, and electrical maintenance of automatic voltage regulators (AVR) and power system stabilizers (PSS).

7.10.2 Automatic Voltage Regulators

Voltage regulators control generator excitation to maintain a constant terminal voltage as the machine is loaded. In general, var flows from a higher voltage to a lower voltage point on the electrical system. Therefore, it is important to maintain the desired generator output terminal voltage to control electrical system var flows.

7.10.3 Power System Stabilizers

PSS are installed on larger generators to dampen out intertie watt oscillations. Each generator has a local mode natural frequency at which it wants to oscillate, and the cumulative effect of operating a number of geographically dispersed generators in a network can create an intertie watt oscillation in the neighborhood of 1.0 cycle per second. The watt oscillations at system intertie points are undesirable, and the stabilizers act on the excitation system to dampen out the oscillations. On older units, the PSS are mounted in separate enclosures, and on newer excitation systems they may be incorporated into the same enclosure as AVR.

7.10.4 Certification Tests

Accurate models of generators that feed the bulk power electrical system (100 kV and higher) and their associated controls are necessary for realistic simulations of the electrical grid. Baseline testing and periodic performance validation are required by regional transmission authorities to ensure that the dynamic models and databases that are used in the grid simulations to represent plant excitation systems are accurate and up to date. The testing involves off-line tests as well as full load dynamic testing and is normally performed by an excitation engineering specialist.

Each bulk power generating unit should have an excitation system model that was certified by dynamic testing. The certification document and associated testing reports should be maintained in the station file system.

Recertification testing of bulk power generators is normally performed during major unit overhauls at approximately 5-year intervals to ensure that the excitation model has not changed. New generation or units with modifications that could impact the excitation system model should be tested within 180 days of a start or restart date.

7.10.5 Routine Tests

The following tasks should be completed prior to the full load dynamic testing:

- Where possible, megger and inspect CTs and PTs and associated wiring.
- Perform a thorough mechanical check of the switches, wiring terminals, and auxiliary relays and timers. Contacts should be cleaned as required. Dirt and contamination should be removed with a soft brush, or by low-pressure dry air, or vacuum.
- Electrical testing should be performed to prove that the voltage regulator is controlling properly and volts/Hz and reactive ampere limiters are functioning properly. PSS should be checked for proper tuning.
- Prove that tripping and alarm circuits will perform their intended operations.
- Make a final in-service test with the unit on-line to prove that the voltage regulator and PSSs are being supplied the proper currents

and potentials, and, by observation, determine that the equipment appears to be functioning properly.

7.10.6 Generating Station Responsibilities

- Each generating station should maintain files on their excitation system certifications and routine tests. The associated station drawings must be maintained accurately. Files shall also be maintained on the investigation of voltage regulator and PSS failures.
- The individual generating station failure investigation reports should be sent to the generator excitation engineering support group in a timely manner for further analysis and possible upgrades to mitigate reoccurrence.
- Routine test cards or labels shall be visibly mounted on voltage regulator and PSS equipment. The cards or labels should show the date of the last routine test and the name of the responsible technician or engineer.

7.10.7 Excitation Engineering Responsibilities

- The excitation engineering group is responsible for reviewing and improving the design and calculating settings for generating station AVR and PSS systems.
- The excitation engineering group will also maintain files on key electrical drawings, instruction manuals, reference books, settings and associated calculations, and their analysis of excitation system failures.
- The excitation engineering group is responsible for developing routine test procedures for proving that voltage regulators and PSSs are functioning according to the intended design.
- The excitation engineering group will either perform the routine testing of AVR and PSS systems or will train station forces to perform the tests and provide testing and troubleshooting support as required.
- The excitation engineering group is responsible for performing dynamic testing for certification and recertification purposes.

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- Provides a balanced cookbook approach to calculating auxiliary power and generator protective relay settings—one that avoids nuisance tripping and protects apparatus
- Presents electrical operations and maintenance guidelines for generating stations and industrial plants

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