SECTION 23
POWER QUALITY AND RELIABILITY

Surya Santoso
Senior Member IEEE, Assistant Professor, Electrical and Computer Engineering, University of Texas at Austin

Mark F. McGranaghan
Senior Member IEEE, Associate Vice President, EPRI Solutions, Inc., Knoxville, TN.

Roger C. Dugan
Fellow IEEE, Senior Consulting Engineer, EPRI Solutions, Inc., Knoxville, TN.

CONTENTS

23.1 PERSPECTIVE ON POWER QUALITY 23-2
23.1.1 Introduction 23-2
23.2 CATEGORIES AND CHARACTERISTICS OF POWER QUALITY DISTURBANCE PHENOMENA 23-3
23.2.1 General 23-3
23.2.2 General Classes of Power Quality Disturbances . . .23-3
23.2.3 Transient-General 23-4
23.2.4 Short-Duration Voltage Variations 23-4
23.2.5 Long-Duration Voltage Variations 23-7
23.2.6 Sustained Interruption 23-9
23.2.7 Voltage Imbalance 23-9
23.2.8 Waveform Distortion 23-9
23.2.9 Voltage Fluctuation 23-12
23.2.10 Power Frequency Variations 23-12
23.3 VOLTAGE SAGS AND INTERRUPTIONS ON POWER SYSTEMS 23-13
23.3.1 Characteristics 23-13
23.3.2 Sources of Sags and Interruptions 23-14
23.3.3 Utility System Fault Clearing 23-14
23.3.4 Reclosers 23-14
23.3.5 Reclosing Sequence 23-15
23.3.6 Fuse Saving or Fast Tripping 23-16
23.3.7 Fault-Induced Voltage Sags 23-17
23.3.8 Motor Starting Sags 23-19
23.3.9 Motor Starting Methods 23-19
23.3.10 Estimating the Sag Severity during Full Voltage Starting 23-20
23.4 ELECTRICAL TRANSIENT PHENOMENA 23-21
23.4.1 Sources and Characteristics 23-21
23.4.2 Capacitor Switching Transient Overvoltages 23-21
23.4.3 Magnification of Capacitor Switching Transient Overvoltages 23-23
23.4.4 Options to Limit Magnification 23-24
23.4.5 Options to Limit Capacitor Switching Transients—Preinsertion 23-24

23.4.6 Options to Limit Capacitor Transient Switching—Synchronous Closing 23-26
23.4.7 Lightning 23-26
23.4.8 Low-side surges 23-27
23.4.9 Low-Side Surges—An Example 23-28
23.4.10 Ferroresonance 23-28
23.4.11 Transformer Energizing .23-30
23.5 POWER SYSTEMS HARMONICS 23-31
23.5.1 General 23-31
23.5.2 Harmonic Distortion 23-32
23.5.3 Voltage and Current Distortion 23-32
23.5.4 Power System Quantities under Nonsinusoidal Conditions 23-34
23.5.5 RMS Values of Voltage and Current 23-34
23.5.6 Active Power 23-34
23.5.7 Reactive Power 23-35
23.5.8 Power Factor 23-37
23.5.9 Harmonic Phase Sequence 23-37
23.5.10 Triplen Harmonics 23-38
23.5.11 Triplen Harmonics in Transformers 23-38
23.5.12 Total Harmonic Distortion 23-39
23.5.13 Total Demand Distortion 23-40
23.5.14 System Response Characteristics 23-40
23.5.15 System Impedance 23-40
23.5.16 Capacitor Impedance 23-42
23.5.17 Parallel and Series Resonance 23-42
23.5.18 Effects of Resistance and Resistive Load 23-43
23.5.19 Harmonic Impacts 23-43
23.5.20 Control of Harmonics 23-44
23.6 ELECTRICAL POWER RELIABILITY AND RECENT BULK POWER OUTAGES 23-44
23.6.1 Electric Power Distribution Reliability—General .23-44
23.6.2 Electric Power Distribution Reliability Indices . . .23-45
23.6.3 Major Bulk Electric Power Outages 23-45
23.6.4 Great Northeast Blackout of 1965 23-46
23.6.5 New York Blackout of 1977 23-46
23.6.6 The Northwestern Blackout of July 1996 23-47
23.6.7 The Northwestern Blackout of August 1996 23-47
23.6.8 The Great Northeastern Power Blackout of 2003 [22, 23] 23-47
23.6.9 Power Quality Characteristics in the Great Northeastern Power Blackout of 2003 23-48
REFERENCES 23-50

23.1 PERSPECTIVE ON POWER QUALITY

23.1.1 Introduction

Power quality is about compatibility between the quality of the voltage supplied from the electric power system and the proper operation of end-use equipment. Power quality is also about economics—finding the optimum level of investment in the power system and the end-use equipment to achieve the compatibility. There are two categories of power quality that need to be considered—steady-state (or continuous) power quality and disturbances. Steady-state power quality characteristics include voltage regulation, harmonic distortion, unbalance, and flicker. We can define *compatibility levels* for these characteristics and then the challenge is to maintain performance within these compatibility levels and make sure that equipment can operate with these levels. Power quality disturbances (outages, momentary interruptions, voltage sags, and transients) are much more of a challenge. It is impossible to completely prevent disturbances that may cause equipment disruptions. Therefore, we have to find the best balance between investments to prevent disturbances and investments in equipment and facility protection.

On the technology side, future power quality research will focus on advanced technologies that can be applied at all levels of the system to improve compatibility (both supply-side technologies and end-user technologies) and on the procedures to find the optimum places to make these investments from a system perspective. The result will be guidance regarding expected levels of performance for different types of supply systems that will result in optimum economics if customers also make the associated investments to assure that the required equipment performance. Recommendations from the economic analysis will also require regulatory structures to support the implementation of optimum system designs and solutions. Therefore, the research results must be coordinated with development of regulations and market structures for future power systems.

23.2 CATEGORIES AND CHARACTERISTICS OF POWER QUALITY DISTURBANCE PHENOMENA

23.2.1 General

Power quality is a generic term applied to a wide variety of electromagnetic phenomena on the power system. The duration of these phenomena ranges from a few nanoseconds (e.g., lightning strokes) to a few minutes (e.g., feeder voltage regulations) to steady-state disturbances (harmonic distortions and voltage fluctuations). Due to the extensive variety of the phenomena, many power quality terms have sometimes been applied incorrectly and cause confusion among end users, vendors, and service providers in dealing with power quality concerns. For example, a term *power surge* has been used to describe some kind of power disturbances. However, it is ambiguous and in fact has no technical meaning since power surge does not refer to a surge in power. This term has been used to refer to overvoltage transients in voltage. Power is related to the product of voltage and current. Normally, *voltage* is the quantity causing the observed disturbance and the resulting power will not necessarily be directly proportional to the voltage. The solution will generally be to correct or limit the voltage as opposed to addressing the power. Therefore, the use of ambiguous and nonstandard terms is discouraged.

23.2.2 General Classes of Power Quality Disturbances

The Institute of Electrical and Electronics Engineers Standards Coordinating Committee 22 (IEEE SCC22) has led the main effort in the United States to coordinate power quality standards. It has the responsibilities across several societies of the IEEE, principally the Industry Applications Society and the Power Engineering Society. It coordinates with international efforts through liaisons with the IEC and CIGRE (International Conference on Large High-Voltage Electric Systems). The IEC classifies electromagnetic phenomena into the groups shown in Table 23-1[1].

The U.S. power industry efforts to develop recommended practices for monitoring electric power quality have added a few terms to the IEC terminology [2]. *Sag* is used as a synonym to the IEC term *dip*. The category *short duration variations* is used to refer to voltage dips and short interruptions. The term *swell* is introduced as an inverse to sag (dip). The category *long duration variation* has been added to deal with American National Standards Institute (ANSI) C84.1 limits. The category *noise* has been added to deal with broadband conducted phenomena. The category *waveform distortion* is used as a container category for the IEC *harmonics, interharmonics*, and *dc in ac networks* phenomena as well as an additional phenomenon from IEEE Std. 519-1992 (Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems), called *notching*. Table 23-2 shows the categorization of electromagnetic phenomena used for the power quality community.

23.2.3 Transient—General

The term *transient* has long been used in the analysis of power system variations to denote an event that is undesirable and momentary in nature. Other definitions in common use are broad in scope and simply state that a transient is "that part of the change in a variable that disappears during transition from one steady-state operating condition to another" [8]. Another word in common usage that is often considered synonymous with transient is *surge*. This term should be avoided unless it is qualified with appropriate explanation. In general, transients can be classified into two categories, impulsive and oscillatory. These terms reflect the waveshape of a current or voltage transient.

TABLE 23-1 Principal Phenomena Causing Electromagnetic Disturbances as Classified by the IEC

Conducted low-frequency phenomena
Harmonics, interharmonics
Signal systems (power line carrier)
Voltage fluctuations (flicker)
Voltage dips and interruptions
Voltage imbalance (unbalance)
Power-frequency variations
Induced low-frequency voltages
DC in ac networks
Radiated low-frequency phenomena
Magnetic fields
Electric fields
Conducted high-frequency phenomena
Induced continuous wave (CW) voltages or currents
Unidirectional transients
Oscillatory transients
Radiated high-frequency phenomena
Magnetic fields
Electric fields
Electromagnetic fields
Continuous waves
Transients
Electrostatic discharge phenomena (ESD)
Nuclear electromagnetic pulse (NEMP)

Impulsive Transient. An *impulsive transient* is a sudden, nonpower frequency change in the steady-state condition of voltage, current, or both, that is unidirectional in polarity (primarily either positive or negative). They are normally characterized by their rise and decay times which can also be revealed by their spectral content. For example, a 1.2×50 μs 2000-V impulsive transient nominally rises from zero to its peak value of 2000 V in 1.2 μs, and then decays to half its peak value in 50 μs. The most common cause of impulsive transient is lightning. Figure 23-1 illustrates a typical current impulsive transient caused by lightning.

Oscillatory Transient. An *oscillatory transient* is a sudden, nonpower frequency change in the steady-state condition of voltage, current, or both, that includes both positive and negative polarity values. It consists of a voltage or current whose instantaneous value changes polarity rapidly. It is described by its spectral content (predominate frequency), duration, and magnitude. The spectral content subclasses defined in Table 23-2 are high, medium, and low frequency. The frequency ranges for these classifications are chosen to coincide with common types of power system oscillatory transient phenomena. High- and medium-frequency oscillatory transients are transients with a primary frequency component greater than 500 kHz with a typical duration measured in microseconds, and between 5 and 500 kHz with duration measured in the tens of microseconds, respectively. Figure 23-2 illustrates a medium frequency oscillatory transient event due to back-to-back capacitor energization.

23.2.4 Short-Duration Voltage Variations

Short-duration voltage variations are caused by fault conditions, the energization of large loads that require high starting currents, or intermittent loose connections in power wiring. Depending on the fault location and the system conditions, the fault can cause either temporary voltage drops (sags), or voltage rises (swells), or a complete loss of voltage (interruptions). The fault condition can be close to or remote from the point of interest. In either case, the impact on the voltage during the actual fault condition is of short duration variation until protective devices operate to clear the fault.

TABLE 23-2 Categories and Characteristics of Power System Electromagnetic Phenomena

Categories	Typical Spectral Content	Typical Duration	Typical Voltage Magnitude
1.0 Transients			
1.1 Impulsive			
1.1.1 Nanosecond	5 ns rise	< 50 ns	
1.1.2 Microsecond	1 μs rise	50 ns–1 ms	
1.1.3 Millisecond	0.1 ms rise	> 1 ms	
1.2 Oscillatory			
1.2.1 Low frequency	< 5 kHz	0.3–50 ms	0–4 pu*
1.2.2 Medium frequency	5–500 kHz	20 μs	0–8 pu
1.2.3 High frequency	0.5–5 MHz	5 μs	0–4 pu
2.0 Short duration variations			
2.1 Instantaneous			
2.1.1 Interruption		0.5–30 cycle	< 0.1 pu
2.1.2 Sag (dip)		0.5–30 cycle	0.1–0.9 pu
2.1.3 Swell		0.5–30 cycle	1.1–1.8 pu
2.2 Momentary			
2.2.1 Interruption		30 cycle–3 s	< 0.1 pu
2.2.2 Sag (dip)		30 cycle–3 s	0.1–0.9 pu
2.2.3 Swell		30 cycle–3 s	1.1–1.4 pu
2.3 Temporary			
2.3.1 Interruption		3 s–1 min	< 0.1 pu
2.3.2 Sag (dip)		3 s–1 min	0.1–0.9 pu
2.3.3 Swell		3 s–1 min	1.1–1.2 pu
3.0 Long duration variations			
3.1 Interruption, sustained		> 1 min	0.0 pu
3.2 Undervoltages		> 1 min	0.8–0.9 pu
3.3 Overvoltages		> 1 min	1.1–1.2 pu
4.0 Voltage unbalance		steady state	0.5–2%
5.0 Waveform distortion			
5.1 DC offset		steady state	0–0.1%
5.2 Harmonics	0–100 Hz	steady state	0–20%
5.3 Interharmonics	0–6 kHz	steady state	0–2%
5.4 Notching		steady state	
5.5 Noise	broadband	steady state	0–1%
6.0 Voltage fluctuations	< 25 Hz	intermittent	0.1–7% 0.2–2 Pst
7.0 Power frequency variations		< 10 s	

*pu = per unit.

This category encompasses the IEC category of voltage dips and short interruptions. Each type of variation can be designated as instantaneous, momentary, or temporary, depending on its duration as defined in Table 23-2.

Interruption. An interruption occurs when the supply voltage or load current decreases to less than 0.1 pu for a period of time not exceeding 1 min. Interruptions can be the result of power system faults, equipment failures, and control malfunctions. The interruptions are measured by their duration since

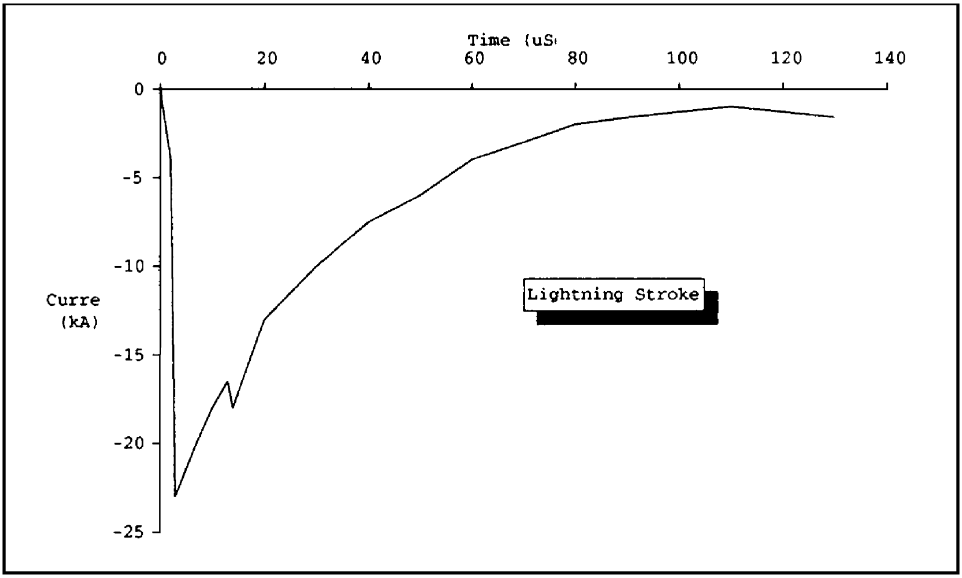

FIGURE 23-1 Lightning stroke current impulsive transient.

the voltage magnitude is always less than 10% of nominal. The duration of an interruption due to a fault on the utility system is determined by the operating time of utility protective devices. Instantaneous reclosing generally will limit the interruption caused by a nonpermanent fault to less than 30 cycles. Delayed reclosing of the protective device may cause an instantaneous, momentary, or temporary interruption. The duration of an interruption can be irregular due to equipment malfunction or loose connections. Some interruptions may be preceded by a voltage sag when the

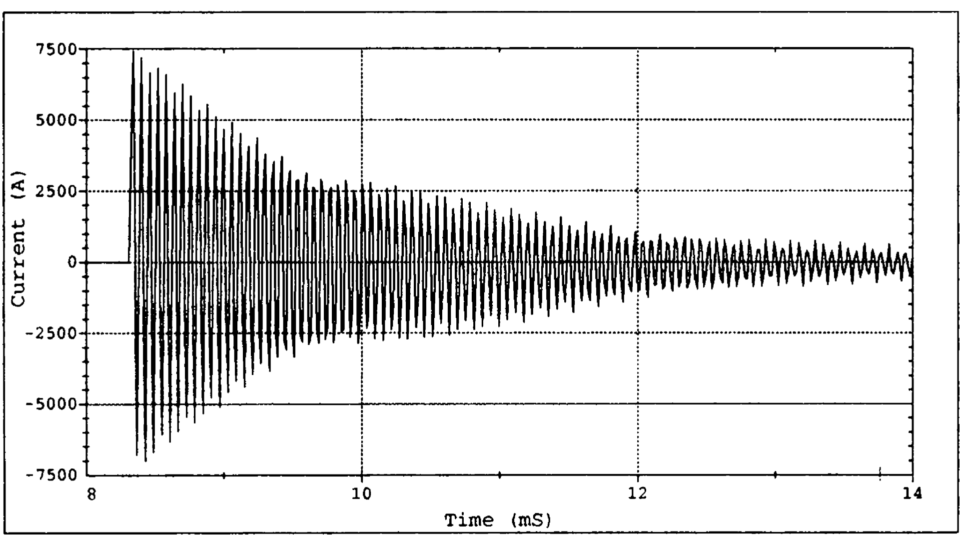

FIGURE 23-2 Oscillatory transient current caused by back-to-back capacitor switching.

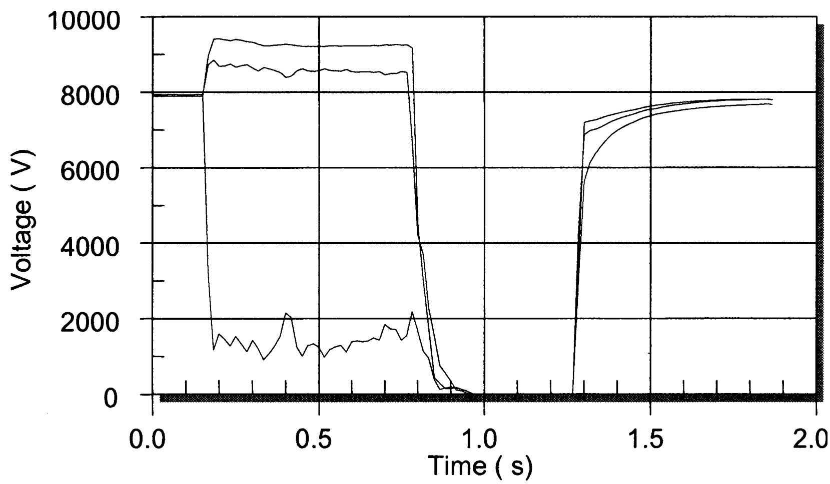

FIGURE 23-3 An instantaneous interruption due to a SLG fault and subsequent recloser operation.

interruptions are due to clearing faults on the source system. The voltage sag occurs between the time a fault initiates and the protective device operates. Figure 23-3 shows a plot of the rms voltages for all three phases for such an interruption. The voltage on the faulted phase initially sags to 15% to 25% for 0.6 s while the fault is arcing. A voltage swell occurs on the other two phases at the same time. The breaker then opens, clears the fault, and recloses successfully 0.4 s later. Utility distribution engineers frequently refer to this as an instantaneous reclose.

Voltage Sags. A sag is a decrease to between 0.1 and 0.9 pu in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 min. The IEC definition for this phenomenon is *voltage dip*. The two terms are considered interchangeable, with sag being the preferred synonym in the U.S. power quality community. Figure 23-4 shows a typical voltage sag associated with a SLG fault on another feeder from the same substation. The voltage sags to 60% for about 5 cycles until the substation breaker is able to interrupt the fault current. Typical fault clearing times range from 3 to 30 cycles, depending on the fault current magnitude and the type of overcurrent protection.

Voltage Swells. A *swell* is defined as an increase to between 1.1 and 1.8 pu in rms voltage or current at the power frequency for durations from 0.5 cycle to 1 min. The term *momentary overvoltage* is used by many writers as a synonym for the term swell. As with sags, swells are usually associated with system fault conditions. One way that a swell can occur is from the temporary voltage rise on the unfaulted phases during a single line-to-ground (SLG) fault. An example is shown in Fig. 23-5. Swells can also be caused by switching off a large load or energizing a large capacitor bank.

23.2.5 Long-Duration Voltage Variations

Long-duration voltage variations encompass rms deviations at power frequencies for longer than 1 min. ANSI C84.1 specifies the steady-state voltage tolerances expected on a power system. A voltage variation is considered to be long duration when the ANSI limits are exceeded for greater than 1 min. Long-duration variations can be either overvoltages or undervoltages. Overvoltages and undervoltages generally are not the result of system faults, but are caused by load variations on the system and system switching operations. Such variations are typically displayed as plots of rms voltage versus time.

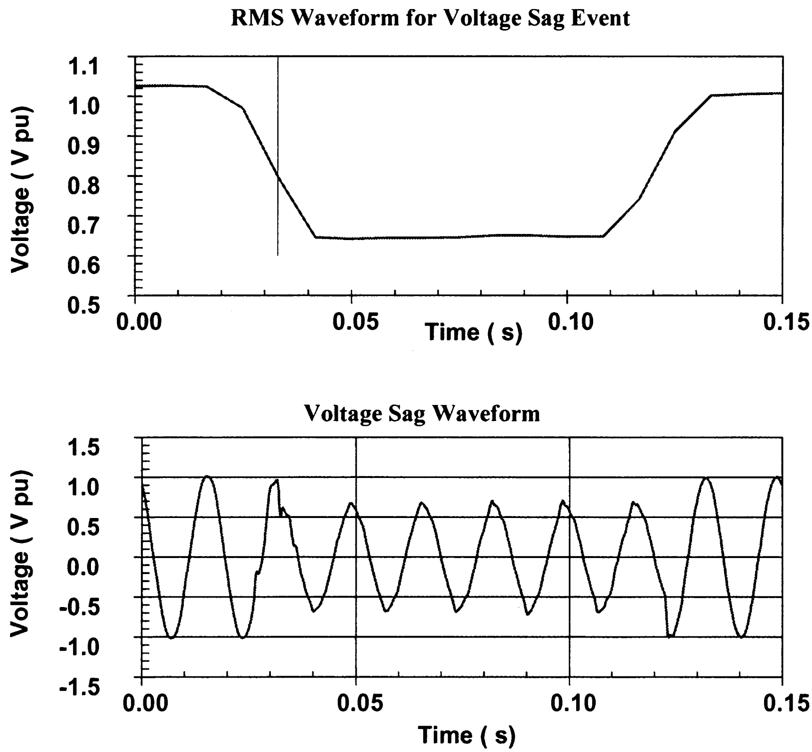

FIGURE 23-4 Voltage sag caused by a SLG fault.

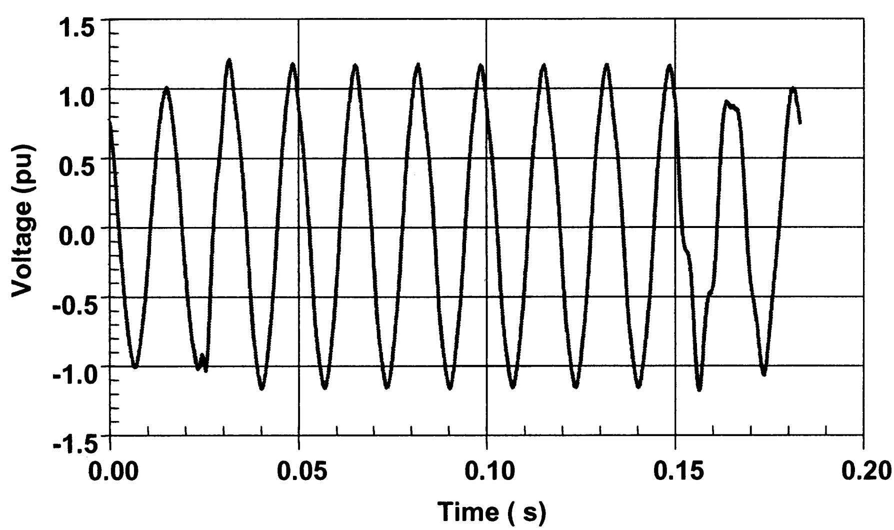

FIGURE 23-5 An 8-cycle voltage swell caused by a SLG fault.

Overvoltage. An *overvoltage* is an increase in the rms ac voltage greater than 110% at the power frequency for a duration longer than 1 min. They are usually the result of load switching (e.g., switching off a large load or energizing a capacitor bank). The overvoltages result because the system is either too weak for the desired voltage regulation or voltage controls are inadequate. Incorrect tap settings on transformers can also result in system overvoltages.

Undervoltage. An *undervoltage* is a decrease in the rms ac voltage to less than 90% at the power frequency for a duration longer than 1 min. They are the result of the events that are the reverse of the events that cause overvoltages. A load switching on or a capacitor bank switching off can cause an undervoltage until voltage regulation equipment on the system can bring the voltage back to within tolerances. Overloaded circuits can result in undervoltages also. The term *brownout* is often used to describe sustained periods of undervoltage initiated as a specific utility dispatch strategy to reduce power demand. Because there is no formal definition for brownout, and it is not as clear as the term undervoltage when trying to characterize a disturbance, the term brownout should be avoided.

23.2.6 Sustained Interruption

When the supply voltage has been zero for a period of time in excess of 1 min, the long duration voltage variation is considered a sustained interruption. Voltage interruptions longer than 1 min are often permanent and require human intervention to repair the system for restoration. The term sustained interruption refers to specific power system phenomena and, in general, has no relation to the usage of the term *outage*. Utilities use outage or interruption to describe phenomena of similar nature for reliability reporting purposes. However, this causes confusion for end users who think of an outage as any interruption of power that shuts down a process. This could be as little as one-half of a cycle. Outage, as defined in IEEE Std 100 [8], does not refer to a specific phenomenon, but rather to the state of a component in a system that has failed to function as expected. Also, use of the term *interruption* in the context of power quality monitoring has no relation to reliability or other continuity of service statistics. Thus, this term has been defined to be more specific regarding the absence of voltage for long periods.

23.2.7 Voltage Imbalance

Voltage imbalance (also called voltage unbalance) is sometimes defined as the maximum deviation from the average of the 3-phase voltages or currents, divided by the average of the 3-phase voltages or currents, expressed in percent. Unbalance is more rigorously defined in the standards [6, 8, 11, 12] using symmetrical components. The ratio of either the negative or zero sequence component to the positive sequence component can be used to specify the percent unbalance. The most recent standard [11] specifies that the negative sequence method be used. Figure 23-6 shows an example of these two ratios for a 1 week trend of imbalance on a residential feeder.

23.2.8 Waveform Distortion

Waveform distortion is defined as a steady-state deviation from an ideal sine wave of power frequency principally characterized by the spectral content of the deviation. There are five primary types of waveform distortion: dc offset, harmonics, interharmonics, notching, and noise.

DC Offset. The presence of a dc voltage or current in an ac power system is termed *dc offset*. This can occur as the result of a geomagnetic disturbance or asymmetry of electronic power converters. Incandescent lightbulb life extenders, for example, may consist of diodes that reduce the rms voltage supplied to the lightbulb by half-wave rectification. Direct current in alternating current networks can have a detrimental effect by biasing transformer cores so they saturate in normal operation. This

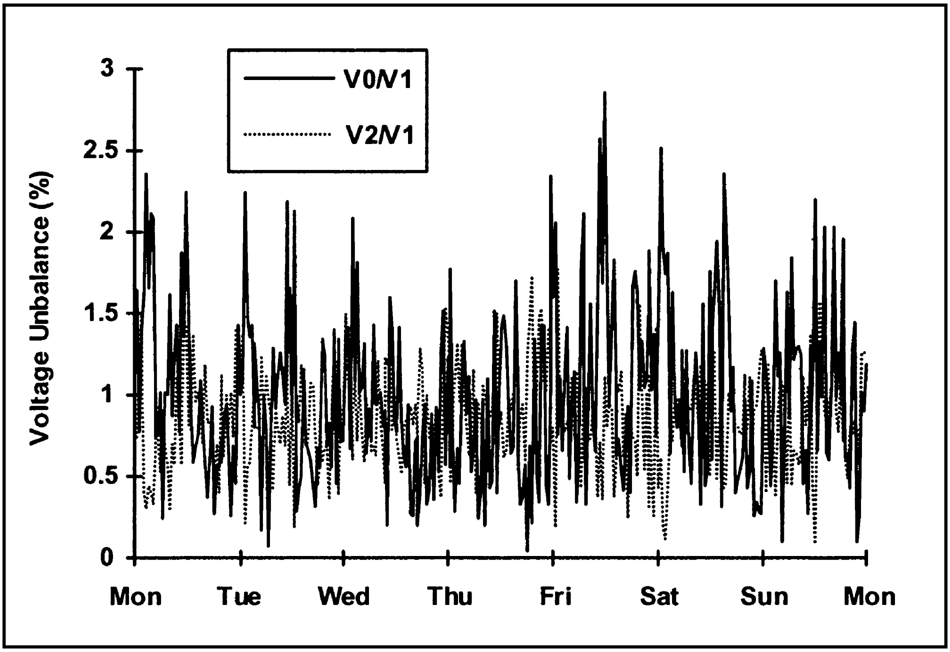

FIGURE 23-6 Voltage unbalance trend for a residential feeder.

causes additional heating and loss of transformer life. DC may also cause the electrolytic erosion of grounding electrodes and other connectors.

Harmonics and Interharmonics. *Harmonics* are sinusoidal voltages or currents having frequencies that are integer multiples of the frequency at which the supply system is designed to operate (termed the fundamental frequency; usually 50 or 60 Hz) [6]. Periodically distorted waveforms can be decomposed into a sum of the fundamental frequency and the harmonics. Harmonic distortion originates in the nonlinear characteristics of devices and loads on the power system. Figure 23-7 illustrates the waveform and harmonic spectrum for a typical adjustable speed drive input current.

Voltages or currents having frequency components that are not integer multiples of the frequency at which the supply system is designed to operate (e.g., 50 or 60 Hz) are called *interharmonics*. They can appear as discrete frequencies or as a wideband spectrum. Interharmonics can be found in networks of all voltage classes. The main sources of interharmonic waveform distortion are static frequency converters, cycloconverters, induction furnaces, and arcing devices. Power line carrier signals can also be considered as interharmonics.

Notching. *Notching* is a periodic voltage disturbance caused by the normal operation of power electronics devices when current is commutated from one phase to another. Since notching occurs continuously, it can be characterized through the harmonic spectrum of the affected voltage. However, it is generally treated as a special case. The frequency components associated with notching can be quite high and may not be readily characterized with measurement equipment normally used for harmonic analysis. Figure 23-8 shows an example of voltage notching from a 3-phase converter that produces continuous dc current. The notches occur when the current commutates from

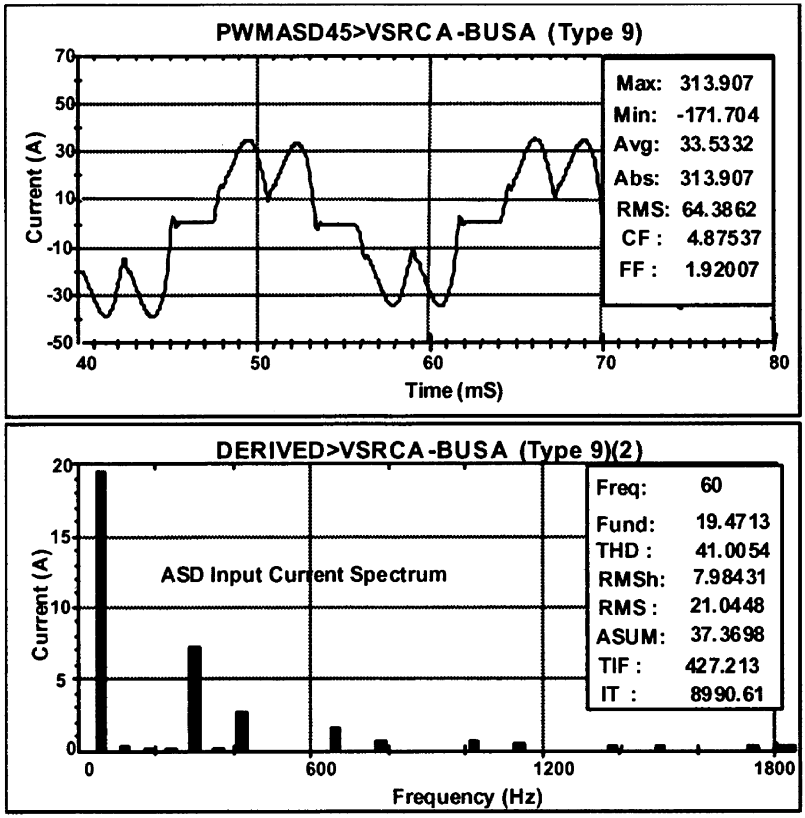

FIGURE 23-7 Current waveform and harmonic spectrum for an ASD input current.

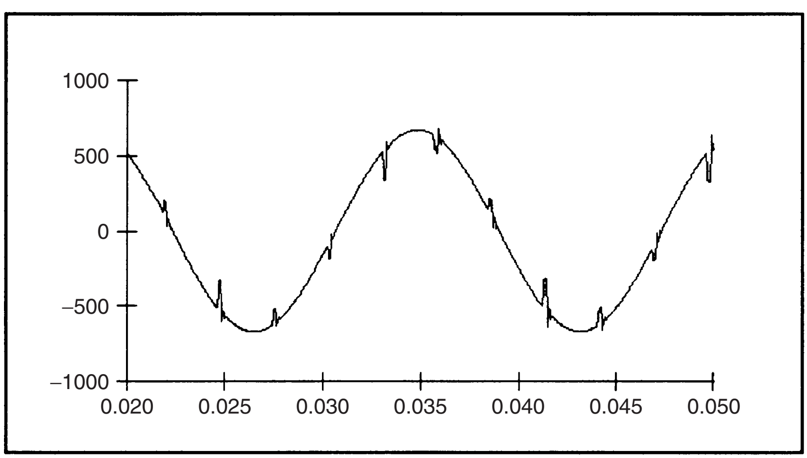

FIGURE 23-8 Example of voltage notching caused by a 3-phase converter.

one phase to another. During this period, there is a momentary short circuit between two phases pulling the voltage as close to zero as permitted by system impedances.

Noise. *Noise* is defined as unwanted electrical signals with broadband spectral content lower than 200 kHz superimposed upon the power system voltage or current in phase conductors, or found on neutral conductors or signal lines. Noise in power systems can be caused by power electronic devices, control circuits, arcing equipment, loads with solid-state rectifiers, and switching power supplies. Noise problems are often exacerbated by improper grounding that fails to conduct noise away from the power system. In principle, noise consists of any unwanted distortion of the power signal that cannot be classified as harmonic distortion or transients. Noise disturbs electronic devices such as microcomputer and programmable controllers. The problem can be mitigated by using filters, isolation transformers, and line conditioners.

23.2.9 Voltage Fluctuation

Voltage fluctuations are systematic variations of the voltage envelope or a series of random voltage changes, the magnitude of which does not normally exceed the voltage ranges specified by ANSI C84.1 of 0.9 to 1.1 pu. IEC 61000-2-1 defines various types of voltage fluctuations. We will restrict our discussion here to IEC 61000-2-1 Type (d) voltage fluctuations, which are characterized as a series of random or continuous voltage fluctuations. Loads that can exhibit continuous, rapid variations in the load current magnitude can cause voltage variations that are often referred to as flicker. The term *flicker* is derived from the impact of the voltage fluctuation on lamps such that they are perceived to flicker by the human eye. To be technically correct, voltage fluctuation is an electromagnetic phenomenon while flicker is an undesirable result of the voltage fluctuation in some loads. However, the two terms are often linked together in standards. Therefore, we will also use the common term voltage flicker to describe such voltage fluctuations. Figure 23-9 illustrates a voltage waveform which produces flicker. This is caused by an arc furnace, one of the most common causes of voltage fluctuations on utility transmission and distribution systems.

23.2.10 Power Frequency Variations

Power frequency variations are defined as the deviation of the power system fundamental frequency from its specified nominal value (e.g., 50 or 60 Hz). The power system frequency is directly related to the rotational speed of the generators supplying the system. There are slight variations in frequency as the dynamic balance between load and generation changes. The size of the frequency shift and its duration depends on the load characteristics and the response of the generation control system

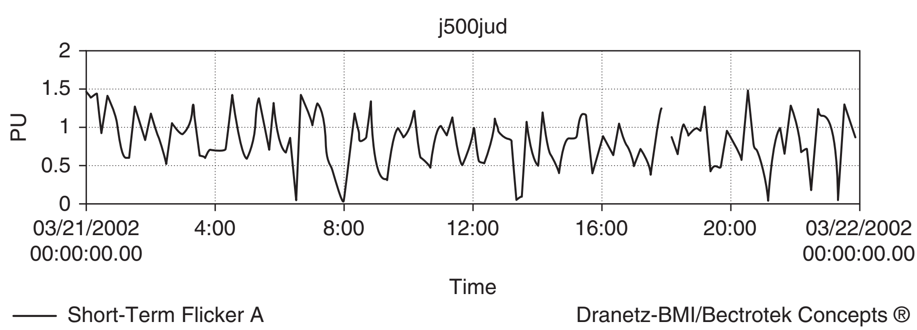

FIGURE 23-9 Flicker (Pst) at 161-kV substation bus measured according to IEC 61000-4-15.

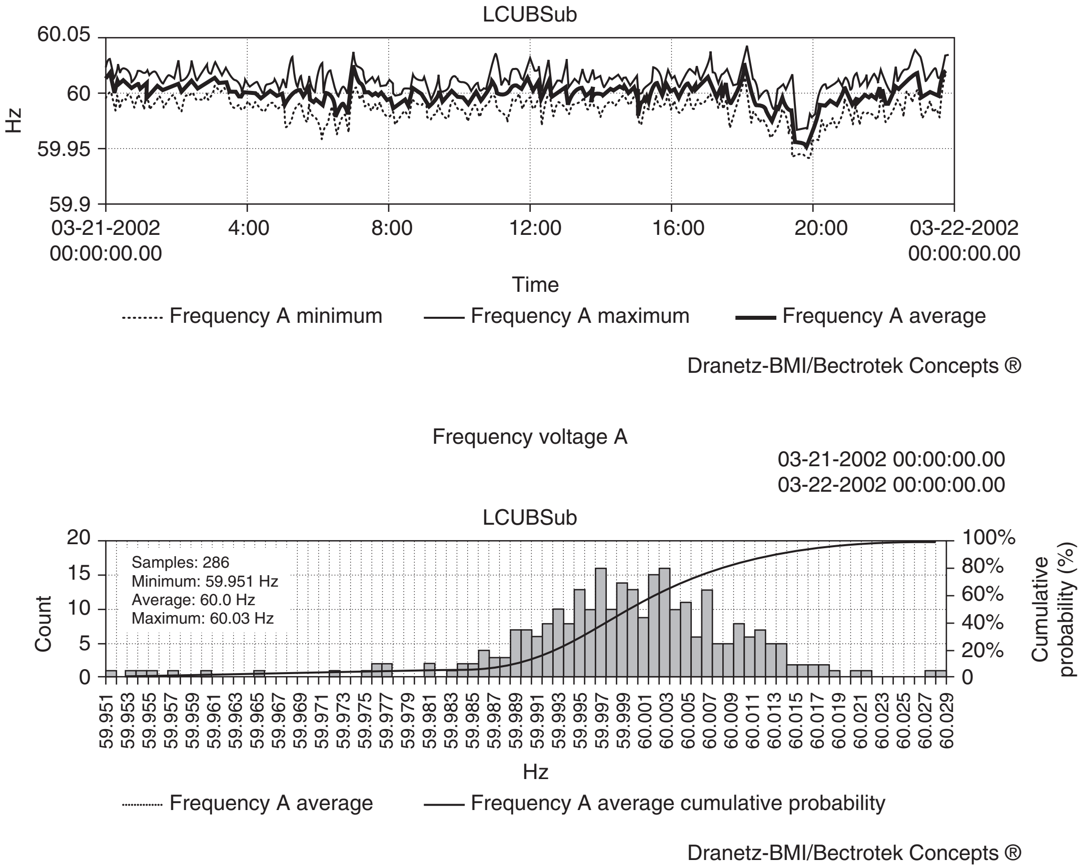

FIGURE 23-10 Power frequency trend and statistical distribution at 13-kV substation bus.

to load changes. Figure 23-10 illustrates frequency variations for a 24-h period on a typical 13-kV substation bus. Frequency variations that go outside of accepted limits for normal steady-state operation of the power system can be caused by faults on the bulk power transmission system, a large block of load being disconnected, or a large source of generation going offline.

23.3 VOLTAGE SAGS AND INTERRUPTIONS ON POWER SYSTEMS

23.3.1 Characteristics

Voltage sags and interruptions are related power quality problems. They are the result of faults in the power system and switching actions to isolate the faulted sections. A voltage sag is characterized by a short duration (typically 0.5 to 30 cycles) reduction in rms voltage caused by faults on the power system and the starting of large loads, such as motors. Momentary interruptions (typically no more than 2 to 5 s) cause a complete loss of voltage and are a common result of the actions taken by utilities to clear transient faults on their systems. Sustained interruptions of longer than 1 min are generally due to permanent faults. Due to the nature of the interconnected power systems and the utility fault-clearing schemes, voltage sags are the most common power quality disturbances.

23.3.2 Sources of Sags and Interruptions

Voltage sags and interruptions are generally caused by faults (short circuits) on the utility system and subsequent operations of protective devices in isolating the faults. Transient or temporary faults on the same or parallel feeders can result in voltage sags. Permanent faults usually result in interruptions. It is also possible that voltage sags are the result of starting of large loads, such as large motors. In some rare circumstances, energizing a transformer in a weak power system can also result in voltage sags. The voltage sag and interruption performance is greatly influenced by the utility feeder design and fault-clearing practices.

23.3.3 Utility System Fault Clearing

A radial distribution system is designed so that only one fault interrupter must operate to clear a fault. For permanent faults, that same device, or another, operates to *sectionalize* the feeder. That is, the faulted section is isolated so that power may be restored to the rest of the loads served from the sound sections. Orchestrating this process is referred to as the *coordination* of the overcurrent protection devices. While this is simple in concept, some of the behaviors of the devices involved can be quite complex. What is remarkable about this is that nearly all of the process is performed automatically by autonomous devices employing only local intelligence.

Overcurrent protection devices appear in series along a feeder. For permanent fault coordination, the devices operate progressively slower as one moves from the ends of the feeders toward the substation. This helps ensure the proper sectionalizing of the feeder so that only the faulted section is isolated. However, this principle is often violated for temporary faults, particularly if *fuse saving* is employed. The typical hierarchy of overcurrent protection devices on a feeder is

Feeder Breaker in the Substation. This is a circuit breaker capable of interrupting typically 40 kA of current and controlled by separate relays. When the available fault current is less than 20 kA, it is common to find reclosers used in this application.

Line Reclosers Mounted on Poles at Midfeeder. The simplest are self-contained with hydraulically-operated timing, interrupting, and reclosing mechanisms. Others have separate electronic controls.

Fuses on Many Lateral Taps Off the Main Feeder. These protective devices have significant implications on power quality issues.

23.3.4 Reclosers

Reclosers are a special circuit breaker designed to perform interruption and reclosing on temporary faults. They can reclose 2 or 3 times if needed in rapid succession. The multiple operations are designed to permit various sectionalizing schemes to operate and to give some more persistent transient faults a second chance to clear. The majority of faults will be cleared on the first operation. These devices can be found in numerous places along distribution feeders and sometimes in substations. They are typically applied at the head of sections subjected to numerous temporary faults. However, they may be applied nearly anywhere a convenient, low-cost primary-side circuit breaker is needed. Figure 23-11 shows a typical pole-mounted line recloser.

In addition to perform interruption and reclosing on temporary faults, reclosers are used for *fuse-saving or fast-tripping* applications. They are some of the fastest mechanical fault interrupters employed on the utility system. While they are typically rated for no faster than 3 to 6 cycles, many examples of interruptions as short as 1.5 cycles have been observed with power quality monitors.

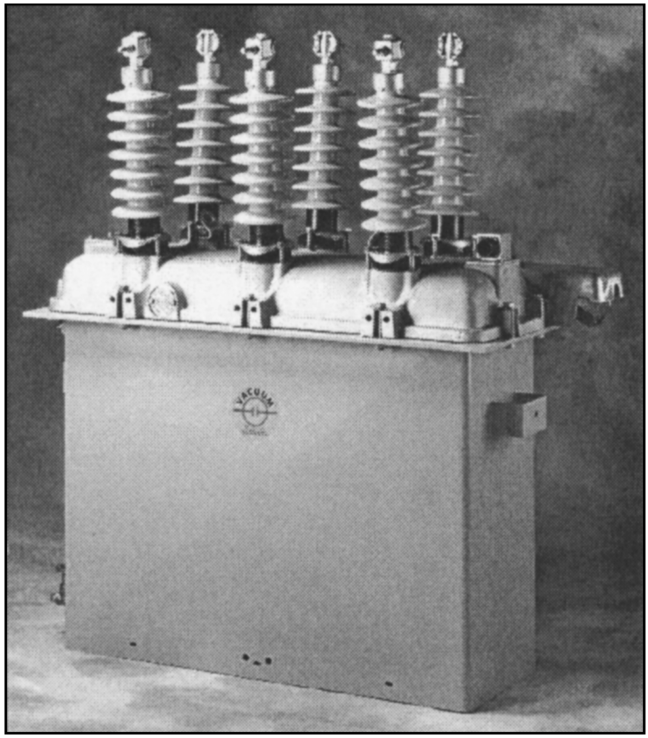

FIGURE 23-11 Typical standard 3-phase oil-insulated line recloser with vacuum interrupters. (*Photo courtesy of Cooper Power Systems.*)

This can be beneficial to limiting sag durations. Where fast tripping is not employed, the recloser control will commonly delay operation to more than 6 cycles to allow time for downline fuses to clear.

23.3.5 Reclosing Sequence

Reclosing is quite prevalent in North American utility systems. Utilities in regions of low lightning incidence may reclose only once because they assume that the majority of their faults will be permanent. In lightning-prone regions, it is common to attempt to clear the fault as many as 4 times. Figure 23-12 illustrates the two most common sequences in use on 4-shot reclosers:

1-fast operation, 3-delayed;

2-fast, 2-delayed.

Reclosers tend to have uniform reclose intervals between operations. The original hydraulic reclosers were limited to about 1 to 2 s and this setting has been retained by many utilities, although modern electronically controlled reclosers can be set for any value. It is common for the first reclose interval on some types of reclosers to be set for *instantaneous reclose*, which will result in closure in 12 to 30 cycles (0.2 to 0.5 s). This is done to reduce the time of the interruption and improve the power quality. However, there are some conflicts created by this, such as with distributed generation disconnecting times.

Substation circuit breakers often have a different style of reclosing sequence as shown in Fig. 23-13. This stems from a different evolution of relaying technology. Reclosing times are counted from the first tripping signal of the first operation. Thus, the common "0-15-45" operating sequence recloses

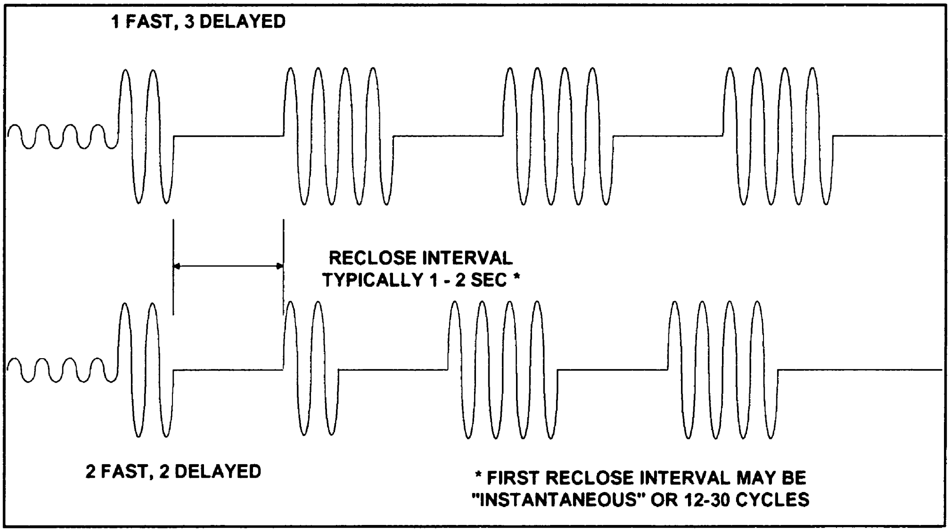

FIGURE 23-12 Common reclosing sequences for line reclosers in use in the United States.

essentially as fast as possible on the first operation, with approximately 15 and 30 s intervals between the next two operations.

Although the terminology may differ, modern breakers and reclosers can both be set to have the same operating sequences to meet load power quality requirements. Utilities generally choose one technology over the other based on cost or construction standards. It is generally fruitless to automatically reclose in distribution systems that are predominantly underground distribution cable, unless there is a significant portion that is overhead and exposed to trees or lightning.

23.3.6 Fuse Saving or Fast Tripping

Ideally, utility engineers would like to avoid blowing fuses needlessly on transient faults because a line crew must be dispatched to change it. Line reclosers were designed specifically to help save fuses. Substation circuit breakers can use instantaneous ground relaying to accomplish the same objective. The

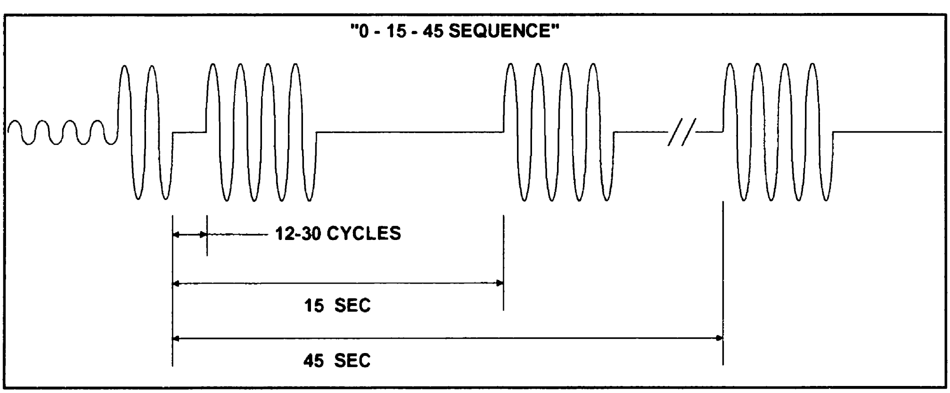

FIGURE 23-13 A common reclosing sequence for substation breakers in the United States.

basic idea is to have the mechanical circuit interrupting device operate very quickly on the first operation so that it clears before any fuses downline from it have a chance to melt. When the device closes back in, power is fully restored in the majority of the cases and no human intervention is required. The only inconvenience to the customer is a slight blink. This is called the fast operation of the device, or the instantaneous trip. If the fault is still there upon reclosing, there are two options in common usage:

1. Switch to a slow, or *delayed*, tripping characteristic. This is frequently the only option for substation circuit breakers; they will operate only one time on the instantaneous trip. This philosophy assumes that the fault is now permanent and switching to a delayed operation will give a downline fuse time to operate and clear the fault by isolating the faulted section.
2. Try a second fast operation. This philosophy is used where experience has shown a significant percentage of transient faults need two chances to clear while saving the fuses. Some line constructions and voltage levels have a greater likelihood that a lightning-induced arc may reignite and need a second chance to clear. Also, a certain percentage of tree faults will burn free if given a second shot.

Many utilities have abandoned fuse saving in selected areas due to complaints about power quality. The fast, or instantaneous, trip is eliminated so that breakers and reclosers have only time-delayed operations.

23.3.7 Fault-Induced Voltage Sags

The majority of voltage sags are caused by faults on the power systems and the subsequent operations of protective devices. Consider a customer that is supplied from the feeder supplied by circuit breaker no. 1 on the diagram shown in Fig. 23-14. If there is a fault on the same feeder, the customer will experience a voltage sag during the fault followed by an interruption when the breaker opens to clear the fault. If the fault is temporary in nature, a reclosing operation on the breaker should be successful and the interruption will only be temporary. It will usually require about 5 or 6 cycles for the breaker to operate, during which time a voltage sag occurs. The breaker will remain open for typically a minimum of 12 cycles up to 5 s depending on utility reclosing practices. Sensitive equipment will almost surely trip during this interruption.

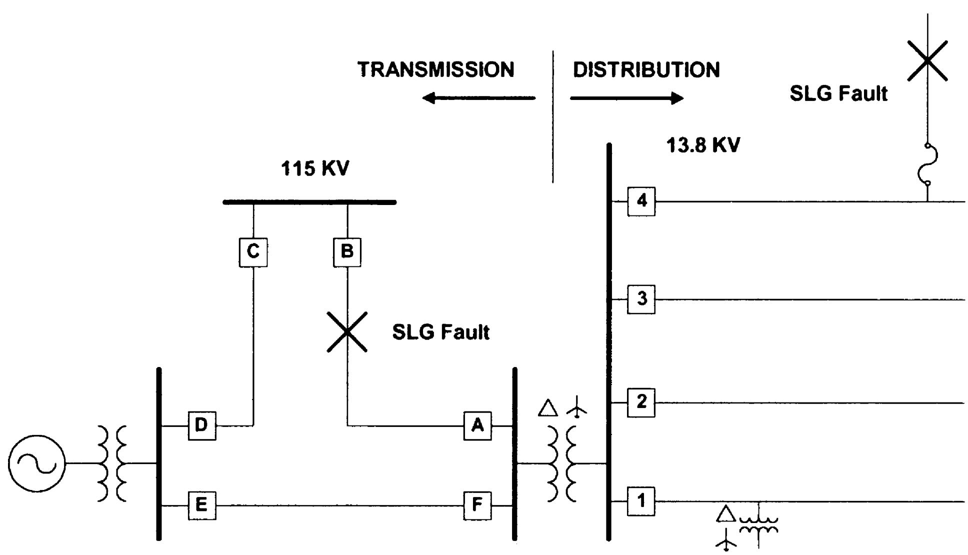

FIGURE 23-14 Fault locations on the utility power system.

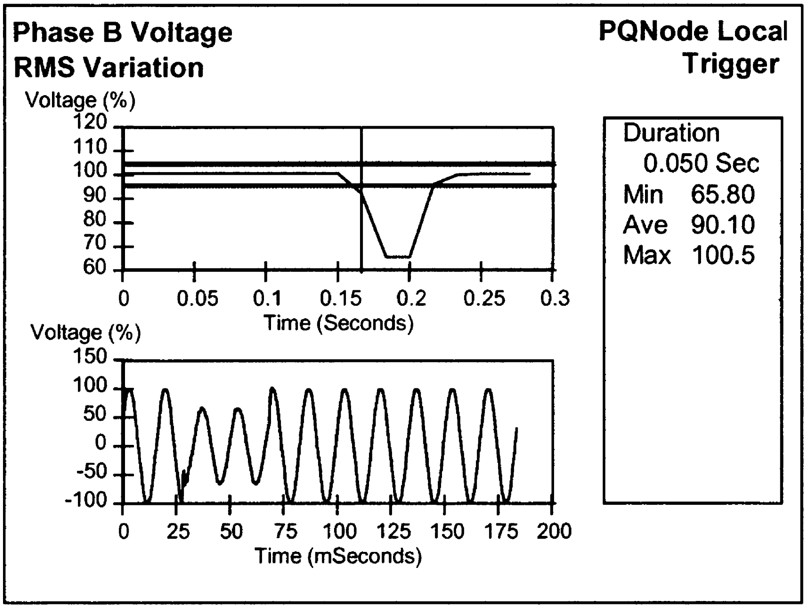

FIGURE 23-15 Voltage sag due to short circuit fault on a parallel utility feeder.

A much more common event would be a fault on one of the other feeders from the substation, that is, a fault is on a parallel feeder, or a fault somewhere on the transmission system (see the fault locations shown on Fig. 23-14). In either of these cases, the customer will experience a voltage sag during the period that the fault is actually on the system. As soon as breakers open to clear the fault, normal voltage will be restored at the customer. Note that to clear the fault shown on the transmission system, both breakers A and B must operate. Transmission breakers will typically clear a fault in 5 or 6 cycles. In this case there are two lines supplying the distribution substation and only one has a fault. Therefore, customers supplied from the substation should expect to see only a sag and not an interruption. The distribution fault on feeder no. 4 may be cleared either by the lateral fuse or the breaker, depending on the utility fuse saving practice. Any of these fault locations can cause equipment to misoperate in customer facilities. The relative importance of faults on the transmission system and the distribution system will depend on the specific characteristics of the systems (underground vs. overhead distribution, lightning flash densities, overhead exposure, etc.) and the sensitivity of the equipment to voltage sags.

Example of Voltage Sags due to a Fault on a Parallel Feeder. This example illustrates voltage sag and momentary interruption events due to a temporary fault on a utility feeder. Figures 23-15 and 23-16 show an interesting utility fault event recorded for an Electric Power Research Institute research project [13,14] by 8010 PQNode instruments* at two locations in the power system. The top chart in each of the figures is the rms voltage variation with time and the bottom chart is the first 175 ms of the actual waveform. Figure 23-15 shows the characteristic measured at a customer location on an unfaulted part of the feeder. Figure 23-16 shows the momentary interruption (actually two separate interruptions) observed downline from the fault. The interrupting device in this case was a line recloser that was able to interrupt the fault very quickly in about 2.5 cycles. This device can have a variety of settings. In this case, it was set for two fast operations and two delayed operations. Figure 23-15 shows only the brief sag to 65% voltage for the first fast operation. There was an

*PQNode is a registered trademark of Dranetz-BMI, Edison, NJ.

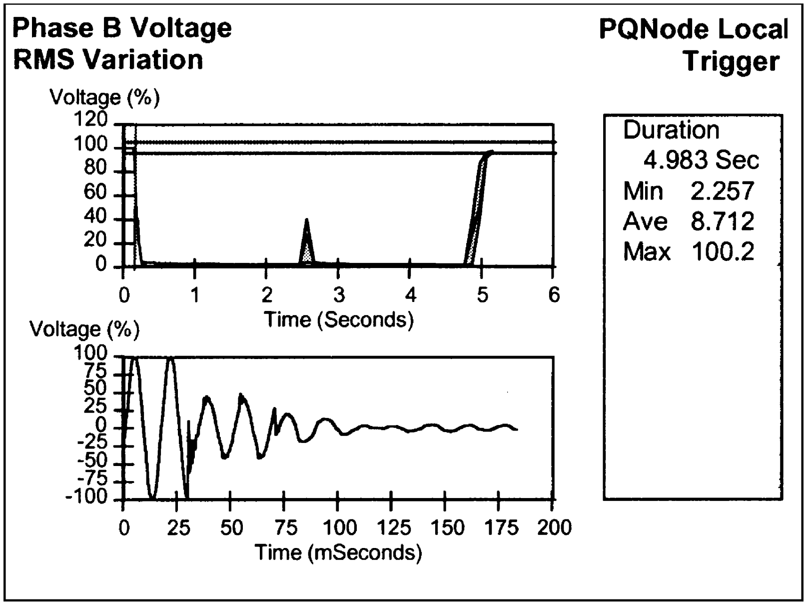

FIGURE 23-16 Utility short circuit fault event with two fast trip operations of utility line.

identical sag for the second operation. While this is very brief sag that is virtually unnoticeable by observing lighting blinks, many industrial processes would have shut down.

Figure 23-16 clearly shows the voltage sag prior to fault clearing and the subsequent two fast recloser operations. The reclose time (the time the recloser was open) was a little more than 2 s, a very common time for a utility line recloser. Apparently, the fault—perhaps, a tree branch—was not cleared completely by the first operation, forcing a second. The system was restored after the second operation.

23.3.8 Motor Starting Sags

Motors have the undesirable effect of drawing several times their full load current while starting. This large current will, by flowing through system impedances, cause a voltage sag which may dim lights, cause contactors to drop out, and disrupt sensitive equipment. The situation is made worse by an extremely poor starting displacement factor—usually in the range of 15%, 30%. The time required for the motor to accelerate to rated speed increases with the magnitude of the sag, and an excessive sag may prevent the motor from starting successfully. Motor starting sags can persist for many seconds, as illustrated in Fig. 23-17.

23.3.9 Motor Starting Methods

Energizing the motor in a single step (*full voltage starting*) provides low cost and allows the most rapid acceleration. It is the preferred method unless the resulting voltage sag or mechanical stress is excessive.

Autotransformer starters have two autotransformers connected in open delta. Taps provide a motor voltage of 80%, 65%, or 50% of system voltage during start-up. Line current and starting torque vary with the square of the voltage applied to the motor, so the 50% tap will deliver only 25% of the full voltage starting current and torque. The lowest tap which will supply the required starting torque is selected.

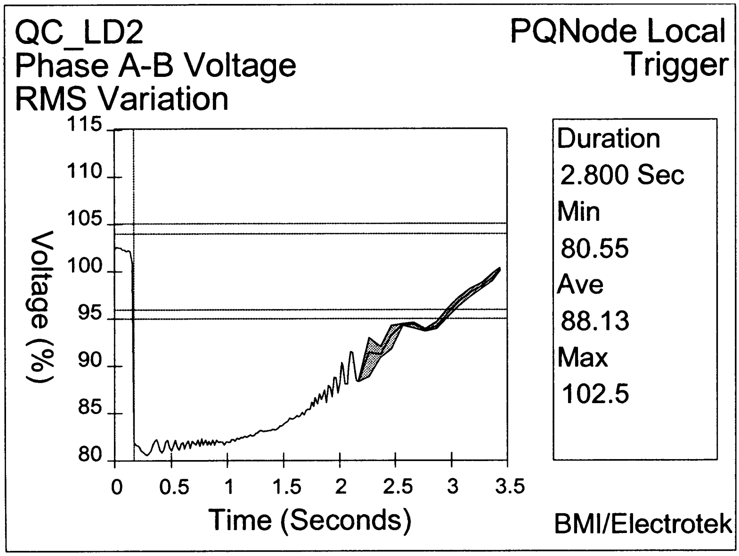

FIGURE 23-17 Typical motor starting voltage sag.

Resistance and reactance starters initially insert an impedance in series with the motor. After a time delay, this impedance is shorted out. Starting resistors may be shorted out over several steps; starting reactors are shorted out in a single step. Line current and starting torque vary directly with the voltage applied to the motor, so for a given starting voltage, these starters draw more current from the line than with autotransformer starters, but provide higher starting torque. Reactors are typically provided with 50%, 45%, and 37.5% taps.

Part winding starters are attractive for use with dual-rated motors (220/440 or 230/460V). The stator of a dual-rated motor consists of two windings connected in parallel at the lower voltage rating, or in series at the higher voltage rating. When operated with a part winding starter at the lower voltage rating, only one winding is energized initially, limiting starting current and starting torque to 50% of the values seen when both windings are energized simultaneously.

Wye-Delta starters connect the stator in wye for starting, then after a time delay, reconnect the windings in delta. The wye connecting reduces the starting voltage to 57% of the system line-line voltage; starting current and starting torque are reduced to 33% of their values for full voltage start.

23.3.10 Estimating the Sag Severity during Full Voltage Starting

As shown in Fig. 23-17, starting an induction motor results in a steep dip in voltage, followed by a gradual recovery. If full voltage starting is used, the sag voltage, in per unit of nominal system voltage is

$$V_{min}(\mathrm{pu}) = \frac{V(\mathrm{pu}) \cdot \mathrm{kVA}_{SC}}{\mathrm{kVA}_{LR} + \mathrm{kVA}_{SC}} \tag{23-1}$$

where $V(\mathrm{pu})$ = is the actual system voltage, in per unit of nominal
kVA_{LR} = is the motor locked rotor kVA
kVA_{SC} = is the system short circuit kVA at the motor

Figure 23-18 illustrates the results of this computation for sag to 90% of nominal voltage, using typical system impedances and motor characteristics.

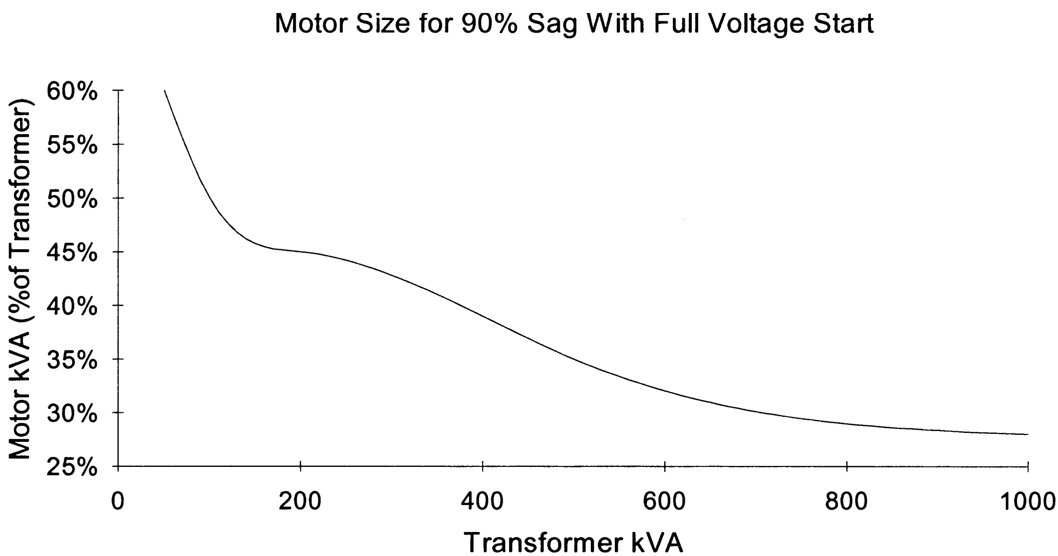

FIGURE 23-18 Typical motor vs. transformer size for full voltage starting sags of 90%.

If the result is above the minimum allowable steady-state voltage for the effected equipment, then the full voltage starting is acceptable. If not, then the sag magnitude versus duration characteristic must be compared to the voltage tolerance envelope of the effected equipment. The required calculations are fairly complicated, and best left to a motor starting or general transient analysis computer program.

23.4 ELECTRICAL TRANSIENT PHENOMENA

23.4.1 Sources and Characteristics

In principle, electrical transient phenomena can be generated due to natural events such as lightning strokes, and switching operations such as capacitor, load, and transformer energizing, and protective device operations. However, two main sources of transient overvoltages on utility systems are capacitor switching and lightning.

23.4.2 Capacitor Switching Transient Overvoltages

Capacitor switching is one of the most common switching events on utility systems. Capacitors are used to provide reactive power (vars) to correct the power factor, which reduces losses and supports the voltage on the system. One drawback to capacitors is that they yield oscillatory transients when switched. Some capacitors are energized all the time (a fixed bank) while others are switched according to load levels. Various control means are used to determine when they are switched including time, temperature, voltage, current, and reactive power. It is common for controls to combine two or more of these functions, such as temperature with voltage override.

Figure 23-19 shows the one-line diagram of a typical utility feeder capacitor switching situation. When the switch is closed, a transient similar to the one in Fig. 23-20 may be observed upline from the capacitor at the monitor location. In this particular case, the capacitor switch contacts close at a point near the system voltage peak. This is common for many types of switches because the insulation across the switch contacts tends to break down when the voltage across the switch is at a maximum

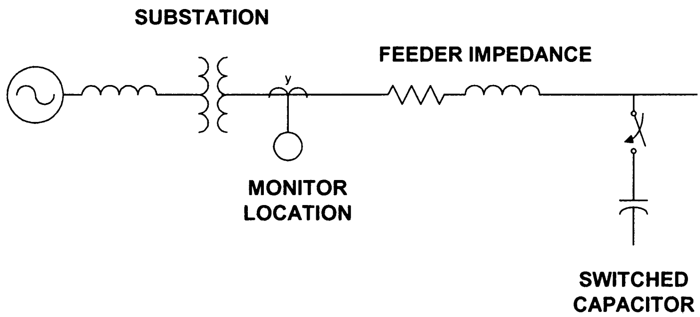

FIGURE 23-19 One-line diagram of capacitor switching operation.

value. The voltage across the capacitor at this instant is zero. Since the capacitor voltage cannot change instantaneously, the system voltage at the capacitor location is briefly pulled down to zero and rises as the capacitor begins to charge toward the system voltage. Because the power system source is inductive, the capacitor voltage overshoots and rings at the natural frequency of the system. At the monitoring location shown, the initial change in voltage will not go completely to zero because of the impedance between the observation point and the switched capacitor. However, the initial drop and subsequent ringing transient that is indicative of a capacitor switching event will be observable to some degree. The overshoot will generate a transient between 1.0 and 2.0 pu depending

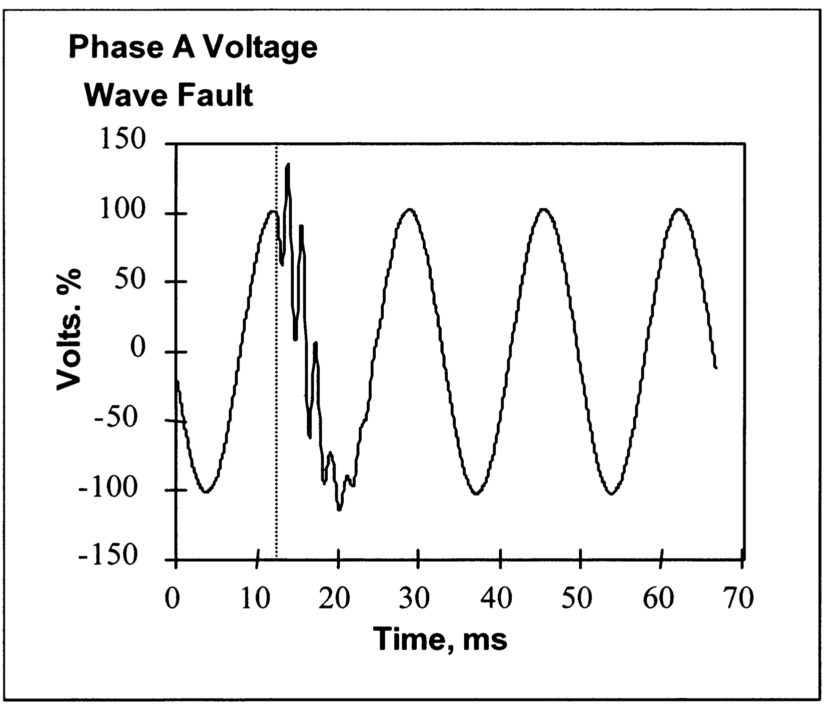

FIGURE 23-20 Typical utility capacitor switching transient reaching 134% voltage, observed upline from the capacitor.

on system damping. In this case, the transient observed at the monitoring location is about 1.34 pu. Utility capacitor switching transients are commonly in the 1.3 to 1.4 pu range, but have also been observed near the theoretical maximum.

23.4.3 Magnification of Capacitor Switching Transient Overvoltages

Capacitor switching transients can propagate into the local power system and will generally pass through distribution transformers into customer load facilities by nearly the amount related to the turns ratio of the transformer. If there are capacitors on the secondary system, the voltage may actually be magnified on the load side of the transformer if the natural frequencies of the systems are properly aligned. The circuit of concern for this phenomenon is illustrated in Fig. 23-21. Transient overvoltages on the end-user side may reach as high as 3.0 to 4.0 pu on the low-voltage bus under these conditions, with potentially damaging consequences for all types of customer equipment.

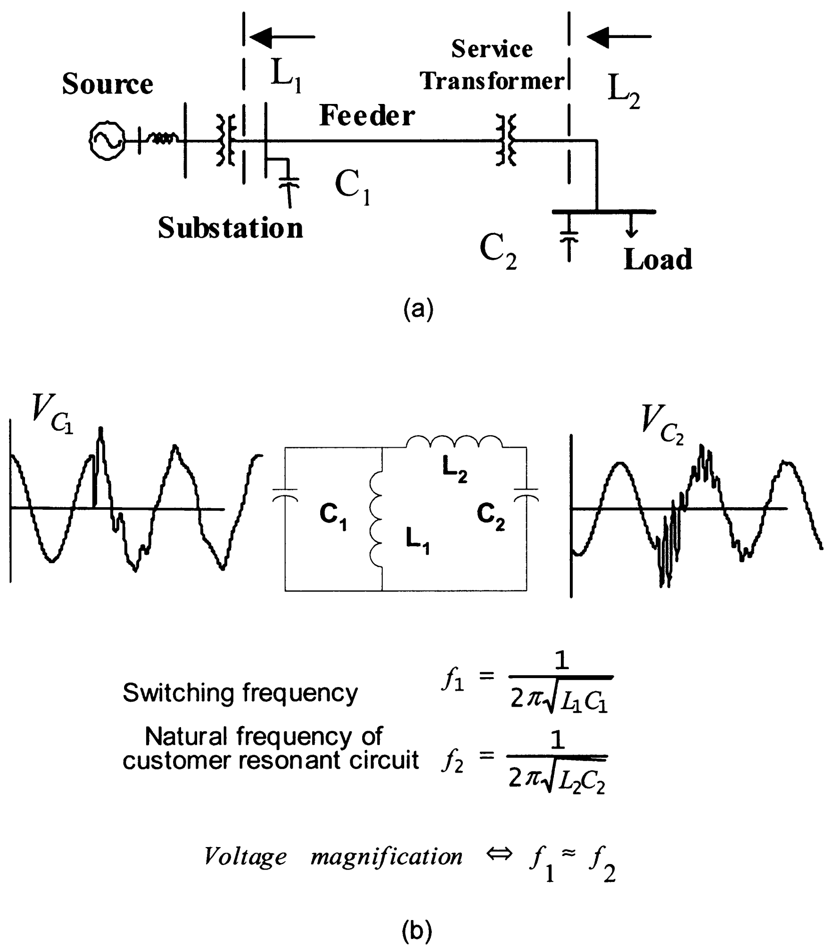

FIGURE 23-21 Voltage magnification of capacitor bank switching. (*a*) Voltage magnification at customer capacitor due to energizing capacitor on utility system (*b*) Equivalent circuit

23.4.4 Options to Limit Magnification

Magnification of utility capacitor switching transients at the end-user location occurs over a wide range of transformer and capacitor sizes. Resizing the customer's power factor correction capacitors or step-down transformer is therefore usually not a practical solution. One solution is to control the transient overvoltage at the utility capacitor. This is sometimes possible using synchronous closing breakers or switches with preinsertion resistors. At the customer location, high-energy surge arresters can be applied to limit the transient voltage magnitude at the customer bus. Energy levels associated with the magnified transient will typically be in the range of 1 kJ. Figure 23-22 shows the expected arrester energy for a range of low-voltage capacitor sizes. High energy MOV arresters for low-voltage applications can withstand 2 to 4 kJ.

While such brief transients up to 2.0 per unit are not generally damaging to the system insulation, it can often cause misoperation of electronic power conversion devices. Controllers may interpret the high voltage as a sign that there is an impending dangerous situation and subsequently disconnect the load to be safe. The transient may also interfere with the gating of thyristors. It is important to note that the arresters can only limit the transient to the arrester protective level. This will typically be approximately 1.8 times the normal peak voltage (1.8 pu).

Another means of limiting the voltage magnification transient is to convert the end-user, power-factor-correction banks to harmonic filters. An inductance in series with the power-factor-correction bank will decrease the transient voltage at the customer bus to acceptable levels. This solution has multiple benefits by providing correction for displacement power factor, controlling harmonic distortion levels within the facility, and limiting the concern for magnified capacitor switching transients.

In many cases, there are only a small number of load devices, such as adjustable-speed motor drives, that are adversely affected by the transient. It is frequently more economical to place line reactors in series with the drives to block the high frequency magnification transient. A 3% reactor is generally effective. While offering only a small impedance to power frequency current, it offers a considerably larger impedance to the transient. Many types of drives have this protection inherently, either through an isolation transformer or a dc bus reactance.

23.4.5 Options to Limit Capacitor Switching Transients—Preinsertion

Preinsertion resistors can reduce the capacitor switching transient considerably. The first peak of the transient is usually the most damaging. The idea is to insert a resistor into the circuit briefly so that the first

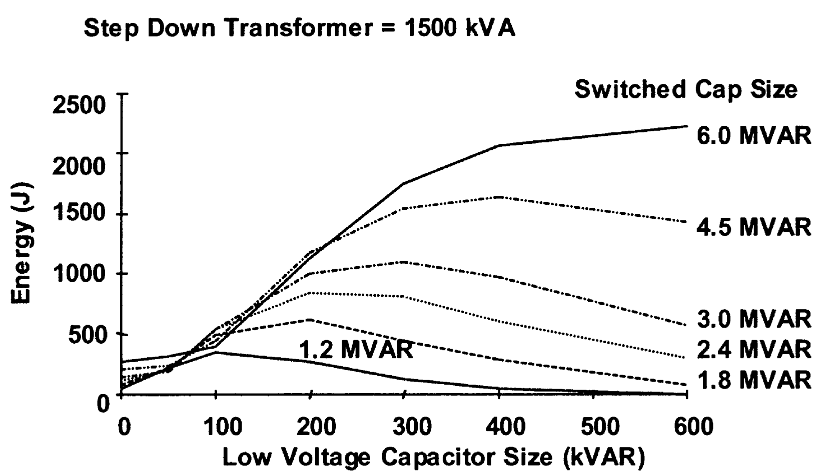

FIGURE 23-22 Arrester energy duty caused by magnified transient.

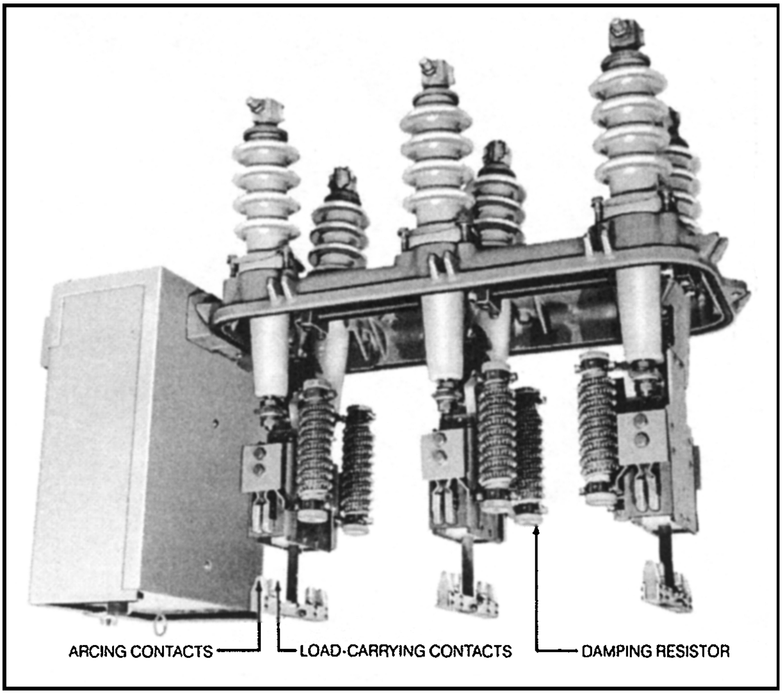

FIGURE 23-23 Capacitor switch with preinsertion resistors. (*Courtesy of Cooper Power Systems.*)

peak is damped significantly. This is old technology, but still quite effective. Figure 23-23 shows one example of a capacitor switch with preinsertion resistors to reduce transients. The preinsertion is accomplished by the movable contacts sliding past the resistor contacts first before mating with the main contacts. This results in a preinsertion time of approximately one-fourth of a cycle at 60 Hz. The effectiveness of the resistors is dependent on capacitor size and available short-circuit current at the capacitor location. Table 23-3 shows expected maximum transient overvoltages upon energization for various conditions, both with and without the preinsertion resistors. These are the maximum values expected; average values are typically 1.3 to 1.4 pu without resistors and 1.1. to 1.2 with resistors.

TABLE 23-3 Peak Transient Overvoltages Due to Capacitor Switching With and Without Preinsertion Resistor

Size, kvar	Avail. Short Circuit, kA	Without Resistor (pu)	With 6.4 Ω Resistor (pu)
900	4	1.95	1.55
900	9	1.97	1.45
900	14	1.98	1.39
1200	4	1.94	1.50
1200	9	1.97	1.40
1200	14	1.98	1.34
1800	4	1.92	1.42
1800	9	1.96	1.33
1800	14	1.97	1.28

Courtesy of Cooper Power Systems

23.4.6 Options to Limit Capacitor Transient Switching—Synchronous Closing

Another popular strategy for reducing transients on capacitor switching is to use a synchronous closing breaker. This is a relatively new technology for controlling capacitor switching transients. Synchronous closing prevents transients by timing the contact closure such that the system voltage closely matches the capacitor voltage at the instant the contacts make. This avoids the step change in voltage that normally occurs when capacitors are switched, causing the circuit to oscillate. Figure 23-24 shows a vacuum switch made for this purpose. It is applied on 46-kV-class capacitor banks. It consists of three independent poles with separate controls. The timing for synchronous closing is determined by anticipating an upcoming voltage zero. Its success is dependent on the consistent operation of the vacuum switch. The switch reduces capacitor inrush currents by an order of magnitude and voltage transients to about 1.1 pu. A similar switch may also be used at distribution voltages. Each of the switches described here requires a sophisticated microprocessor-based control. Understandably, a synchronous closing system is more expensive than a straightforward capacitor switch. However, it is frequently a cost-effective solution when capacitor switching transients are disrupting end-user loads.

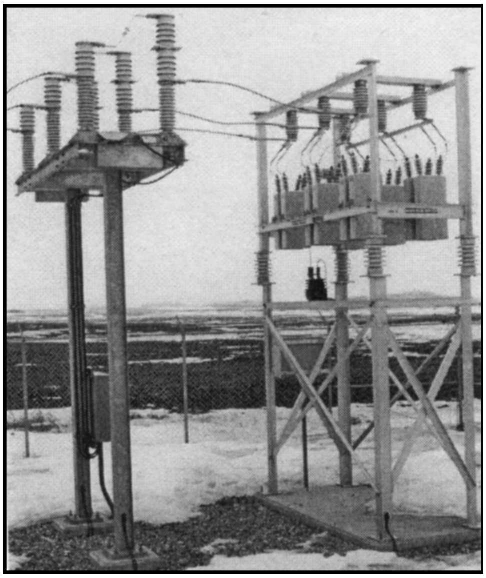

FIGURE 23-24 Synchronous closing capacitor switch. (*Courtesy of Joslyn Hi-Voltage Corporation.*)

23.4.7 Lightning

Lightning is a potent source of impulsive transients and can have serious impacts on power system and end-user equipment. Figure 23-25 illustrates some of the places where lightning can strike that results in lightning currents being conducted from the power system into loads. The most obvious conduction path occurs during a direct strike to a phase wire, either on the primary or the secondary side of the

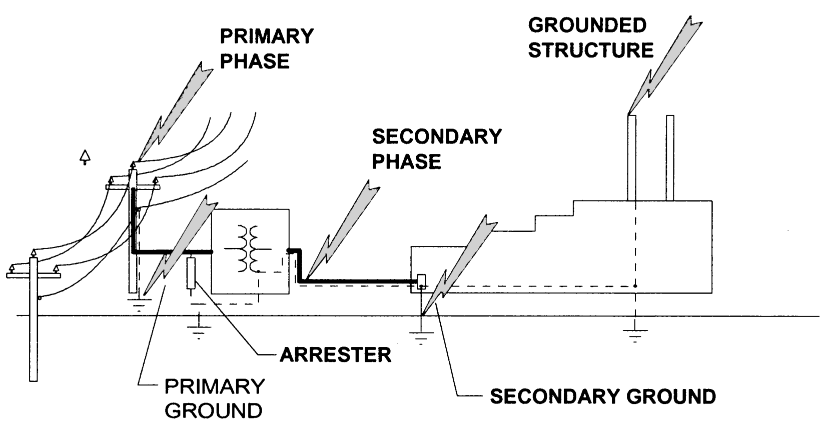

FIGURE 23-25 Stroke locations for conduction of lightning impulses into load facilities.

transformer. This can generate very high overvoltages, but some analysts question whether this is the most common way that lightning surges enter load facilities and cause damage. Very similar transient overvoltages can be generated by lightning currents flowing along ground conductor paths. Note that there can be numerous paths for lightning currents to enter the grounding system. Common ones, indicated by the dotted lines in Fig. 23-25, include the primary ground, the secondary ground, and the structure of the load facilities. Note also that strokes to the primary phase are conducted to the ground circuits through the arresters on the service transformer. Thus, many more lightning impulses may be observed at loads than one might think. Note that grounds are never perfect conductors, especially for impulses. While most of the surge current may eventually be dissipated into the ground connection closest to the stroke, there will be substantial surge currents flowing in other connected ground conductors in the first few microseconds of the strike.

The chief power quality problems with lightning stroke currents entering the ground system are

- They raise the potential of the local ground above other grounds in the vicinity by several kilovolts. Sensitive electronic equipment that is connected between two ground references, such as a computer connected to the telephone system through a modem, can fail when subjected to the lightning surge voltages.
- They induce high voltages in phase conductors as they pass through cables on the way to a better ground.

23.4.8 Low-Side Surges

Some utility and end-user problems with lightning impulses are closely related. One of the most significant ones is called the *low-side surge* problem by many utility engineers. The name was coined by distribution transformer designers because it appears from the transformer's perspective that a current surge is suddenly injected into the low-voltage side terminals. Utilities have not applied secondary arresters at low-voltage levels in great numbers. From the customer's point of view, it appears to be an impulse coming from the utility and is likely to be termed as "secondary surge."

Both problems actually have different side effects of the same surge phenomenon—lightning current flowing from either the utility side or the customer side along the service cable neutral. Figure 23-26 shows one possible scenario. Lightning strikes the primary line and the current is discharged through

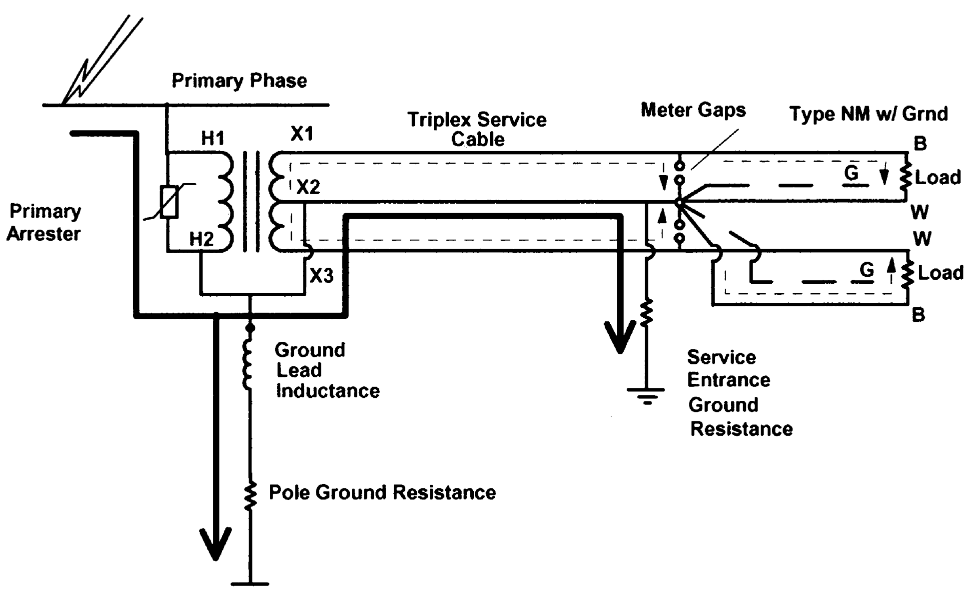

FIGURE 23-26 Primary arrester discharge current divides between pole and load ground.

the primary arrester to the pole ground lead. This lead is also connected to the X2 bushing of the transformer at the top of the pole. Thus, some of the current will flow toward the load ground. The amount of current into the load ground is primarily dependent on the size of the pole ground resistance relative to the load ground. Inductive elements may play a significant role in the current division for the front of the surge, but the ground resistances basically dictate the division of the bulk of the stroke current.

The current that flows through the secondary cables causes a voltage drop in the neutral conductor that is only partially compensated by mutual inductive effects with the phase conductors. Thus, there is a net voltage across the cable, forcing current through the transformer secondary windings and into the load as shown by the dashed lines in the figure. If there is a complete path, substantial surge current will flow. As it flows through the transformer secondary, a surge voltage is induced in the primary, sometimes causing a layer-to-layer insulation failure near the grounded end. If there is not a complete path, the voltage will buildup across the load and may flash over somewhere on the secondary. It is common for the meter gaps to flashover, but not always before there is damage on the secondary because the meter gaps are usually 6 to 8 kV, or higher. The amount of voltage induced in the cable is dependent on the rate-of-rise of the current, which is dependent on other circuit parameters as well as the lightning stroke.

The chief power quality problems this causes are

- The impulse entering the load can cause failure or misoperation of load equipment.
- The utility transformer will fail causing an extended power outage.
- The failing transformer may subject the load to sustained steady-state overvoltages because part of the primary winding is shorted, decreasing the transformer turns ratio. Failure usually occurs in seconds, but has been known to take hours.

The key to this problem is the amount of surge current traveling through the secondary service cable. Keep in mind that the same effect occurs regardless of the direction of the current. All that is required is for the current to get into the ground circuits and for a substantial portion to flow through the cable on its way to another ground. Thus, lightning strikes to either the utility system or the end-user facilities can produce the same symptoms. Transformer protection is more of an issue in residential services, but the secondary transients will appear in industrial systems as well.

23.4.9 Low-Side Surges—An Example

Figure 23-27 shows a waveform of the open-circuit voltage measured at an electrical outlet location in a laboratory mock-up of a residential service [16]. For a relatively small stroke to the primary line (2.6 kA), the voltages at the outlet reached nearly 15 kV. In fact, higher current strokes caused random flashovers of the test circuit, which made measurements difficult. This reported experience is indicative of the capacity of these surges to cause overvoltage problems.

The waveform is a very high-frequency, ringing wave riding on the main part of the low-side surge. The ringing is very sensitive to the cable lengths. A small amount of resistive load, such as a lightbulb, would contribute greatly to the damping. The ringing wave differs depending on where the surge was applied while the base low-side surge wave remains about the same; it is more dependent on the waveform of the current through the service cable. One interesting aspect of this wave is that the ringing is so fast that it gets by the spark gaps in the meter base even though the voltage is 2 times the nominal sparkover value. In the tests, the outlets and lamp sockets could also withstand this kind of wave for about 1 μs before they flashed over. Thus, it is possible to have some high overvoltages propagating throughout the system. The waveform in this figure represents the available open-circuit voltage. In actual practice, a flashover would have occurred somewhere in the circuit after a brief time.

23.4.10 Ferroresonance

The term *ferroresonance* refers to a resonance that involves capacitance and iron-core inductance. The most common condition in which it causes disturbances in the power system is when the magnetizing

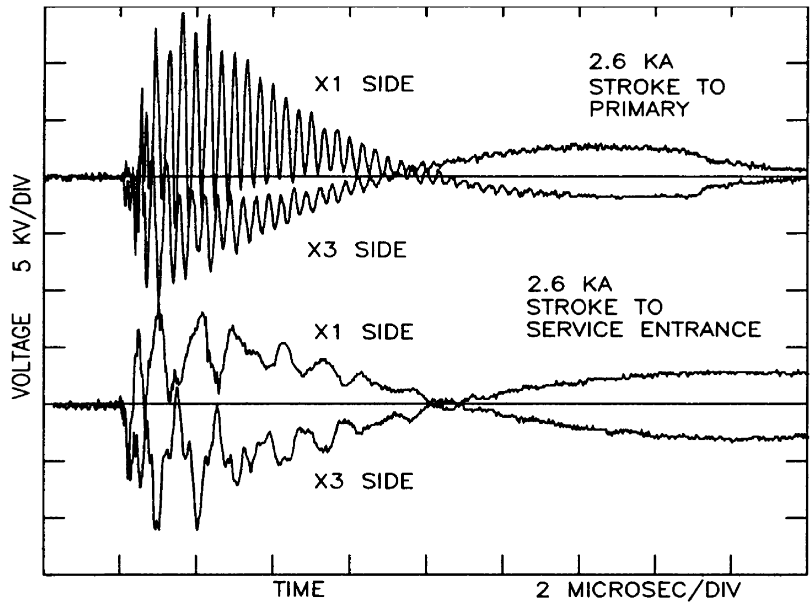

FIGURE 23-27 Voltage appearing at outlet due to low-side surge phenomena.

impedance of a transformer is placed in series with a system capacitor due to an open-phase conductor. Under controlled conditions, ferroresonance can be exploited for useful purpose such as in a constant-voltage transformer. In practice, ferroresonance most commonly occurs when unloaded transformers become isolated on underground cables of a certain range of lengths. The capacitance of overhead distribution lines is generally insufficient to yield the appropriate conditions.

The minimum length of cable required to cause ferroresonance varies with system voltage level. The capacitance of cables is nearly the same for all distribution voltage levels, varying from 40 to 100 nF per 1000 ft, depending on conductor size. However, the magnetizing reactance of a 35-kV-class distribution transformer is several times higher (curve is steeper) than a comparably-sized 15-kV-class transformer. Therefore, damaging ferroresonance has been more common at the higher voltages. For delta-connected transformers, ferroresonance can occur for less than 100 ft of cable. For this reason, many utilities avoid this connection on cable-fed transformers. The grounded wye-wye transformer has become the most commonly used connection in underground systems in North America. It is more resistant, but not immune, to ferroresonance because most units use a three-legged or five-legged core design that couples the phases magnetically. It may require a minimum of several hundred feet of cable to provide enough capacitance to create a ferroresonant condition for this connection. The most common events leading to ferroresonance are

- Manual switching of an unloaded, cable-fed, 3-phase transformer where only one phase is closed (Fig. 23-28*a*). Ferroresonance may be noted when the first phase is closed upon energization or before the last phase is opened on de-energization.
- Manual switching of an unloaded, cable-fed, 3-phase transformer where one of the phases is open (Fig. 23-28*b*). Again, this may happen during energization or de-energization.
- One or two riser-pole fuses may blow leaving a transformer with one or two phases open. Single-phase reclosers may also cause this condition. Today, many modern commercial loads will have controls that transfer the load to backup systems when they sense this condition. Unfortunately, this leaves the transformer without any load to damp out the resonance.
- Phase of a cable connected to a wye-connected transformer.

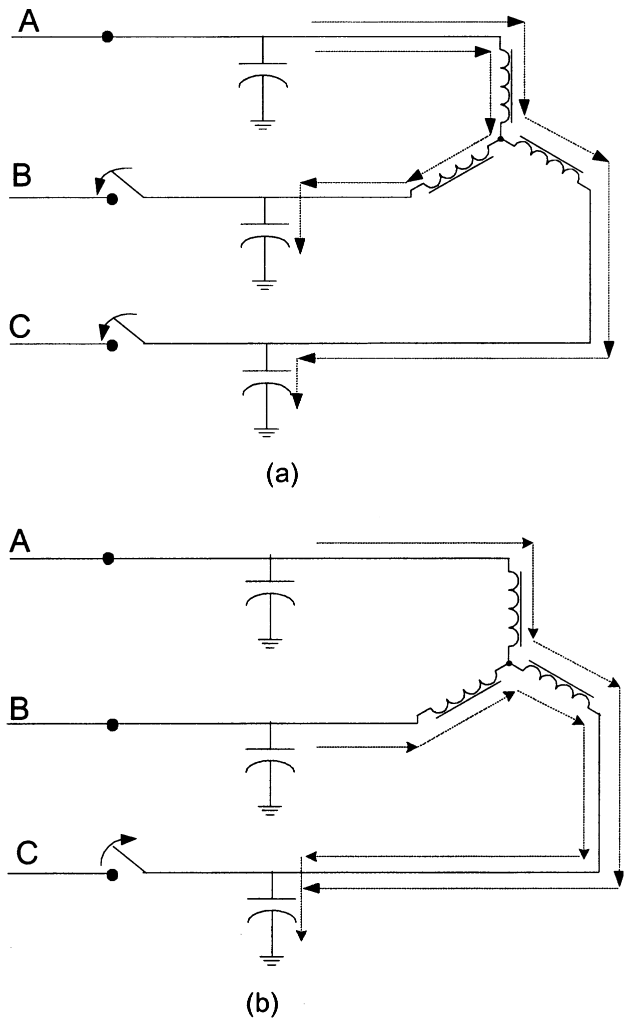

FIGURE 23-28 Common system conditions where ferroresonance may occur: (*a*) one phase closed, (*b*) one phase open.

23.4.11 Transformer Energizing

Energizing a transformer produces inrush currents that are rich in harmonic components for a period lasting up to 1 s. If the system has a parallel resonance near one of the harmonic frequencies, a dynamic overvoltage condition results that can cause failure of arresters and problems with sensitive equipment. This problem can occur when large transformers are energized simultaneously with large power factor correction capacitor banks in industrial facilities. The equivalent circuit is shown in Fig. 23-29. A dynamic overvoltage waveform caused by a third-harmonic resonance in the circuit is shown in Fig. 23-30. After the expected

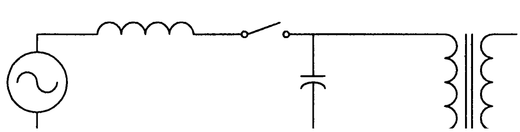

FIGURE 23-29 Energizing a capacitor and transformer simultaneously can lead to dynamic overvoltages.

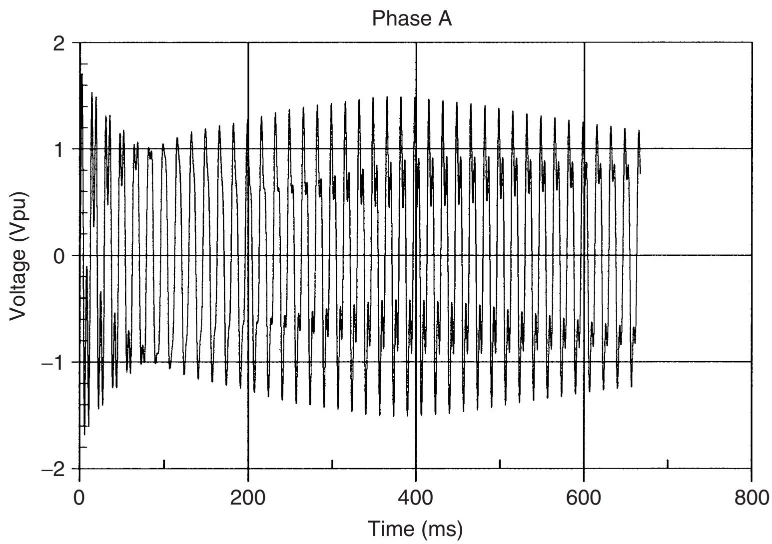

FIGURE 23-30 Dynamic overvoltages during transformer energizing.

initial transient, the voltage again swells to nearly 150% for many cycles until the losses and load damp out the oscillations. This can place severe stress on some arresters and has been known to significantly shorten the life of capacitors.

This form of dynamic overvoltage problem can often be eliminated simply by not energizing the capacitor and transformer together. One plant solved the problem by energizing the transformer first and not energizing the capacitor until load was about to be connected to the transformer.

23.5 POWER SYSTEMS HARMONICS

23.5.1 General

Harmonic distortion is not a new phenomenon on power systems. Concern over distortion has ebbed and flowed a number of times during the history of ac electric power systems. Scanning the technical literature of the 1930s and 1940s, one will notice many articles on the subject. Then the primary sources were the transformers and the primary problem was inductive interference with open-wire telephone systems. The forerunners of modern arc lighting were being introduced and were causing quite a stir because of their harmonic content—not unlike the stir caused by electronic power converters in more recent times.

In contrast, voltage sags and interruptions are nearly universal to every feeder and represent the most numerous and significant power quality deviations. The end user sector suffers more from harmonic problems than the utility sector. Industrial users with adjustable speed drives, arc furnaces, induction furnaces, and the like, are much more susceptible to problems stemming from harmonic distortion.

A good assumption for most utilities in the United States is that the sine wave voltage generated in central power stations is very good. In most areas, the voltage found on transmission systems typically has much less than 1% distortion. However, the distortion increases closer to the load. At some loads, the current waveforms barely resemble a sine wave. Electronic power converters can chop the current into seemingly arbitrary waveforms.

23.5.2 Harmonic Distortion

Harmonic distortion is caused by nonlinear devices in the power system. A nonlinear device is one in which the current is not proportional to the applied voltage. Figure 23-31 illustrates this concept by the case of a sinusoidal voltage applied to a simple nonlinear resistor in which the voltage and current vary according to the curve shown. While the applied voltage is perfectly sinusoidal, the resulting current is distorted. Increasing the voltage by a few percent may cause the current to double and take on a different waveshape. This is the source of most harmonic distortion in a power system. Figure 23-32 illustrates that any periodic, distorted waveform can be expressed as a sum of sinusoids. When a waveform is identical from one cycle to the next, it can be represented as a sum of pure sine waves in which the frequency of each sinusoid is an integer multiple of the fundamental frequency of the distorted wave. This multiple is called a *harmonic* of the fundamental, hence the name of this subject matter. The sum of sinusoids is referred to as a *Fourier series*, named after the great mathematician who discovered the concept.

23.5.3 Voltage and Current Distortion

The term "harmonics" is often used by itself without further qualification. Generally, it could mean one of the following three:

1. The harmonic voltages are too great (the voltage too distorted) for the control to properly determine firing angles.
2. The harmonic currents are too great for the capacity of some device in the power supply system such as a transformer and the machine must be operated at a lower than rated power.
3. The harmonic voltages are too great because the harmonic currents produced by the device are too great for the given system condition.

Clearly, there are separate causes and effects for voltages and currents as well as some relationship between them. Thus, the term harmonics by itself is inadequate to definitively describe a problem. Nonlinear loads appear to be sources of harmonic current in shunt with and injecting

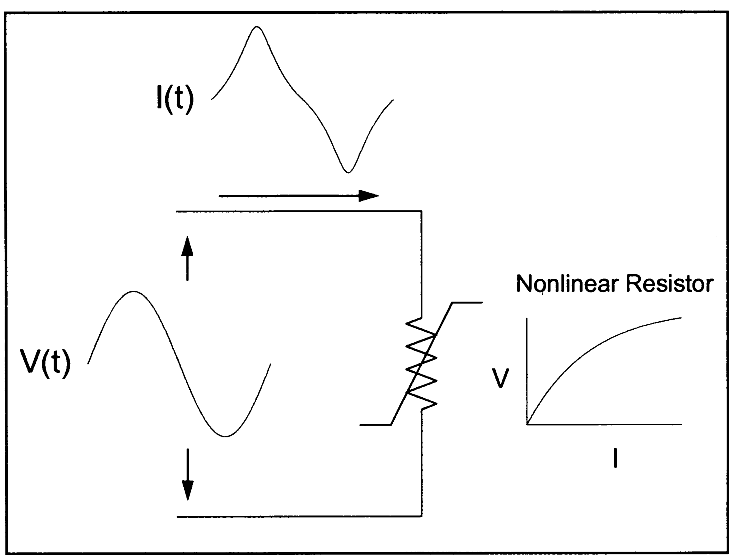

FIGURE 23-31 Current distortion caused by nonlinear resistance.

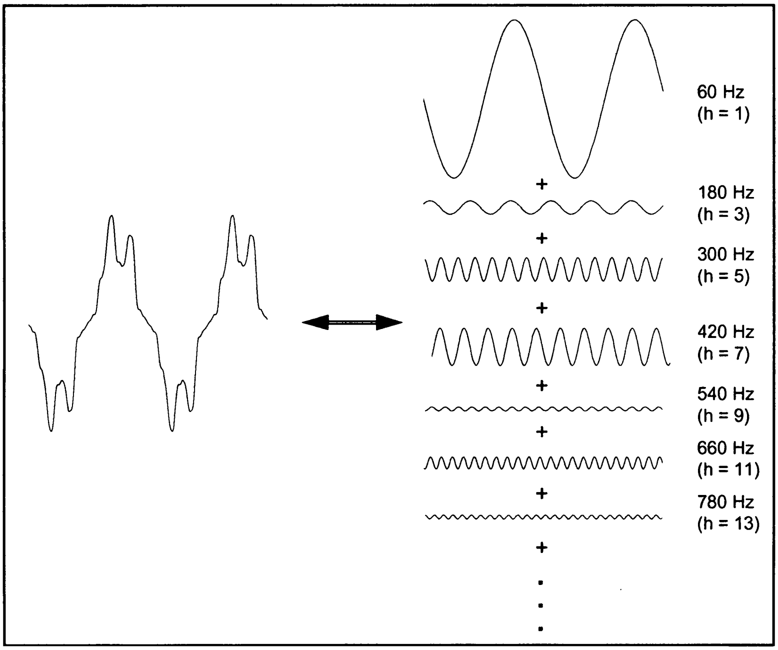

FIGURE 23-32 Fourier series representation of a distorted waveform.

harmonic currents into the power system. For nearly all analyses, it is sufficient to treat these harmonic-producing loads simply as current sources. There are exceptions to this as described later.

Voltage distortion is the result of distorted currents passing through the linear, series impedance of the power delivery system as illustrated in Fig. 23-33. Although, assuming that the source bus is ultimately a pure sinusoid, there is a nonlinear load that draws a distorted current. The harmonic currents passing through the impedance of the system cause a voltage drop for each harmonic. This results in voltage harmonics appearing at the load bus. The amount of voltage distortion depends on the impedance and the current. Assuming the load bus distortion stays within reasonable limits (e.g., less than 5%), the amount of harmonic current produced by the load is generally constant.

While the load current harmonics ultimately cause the voltage distortion, it should be noted that load has no control over the voltage distortion. The same load put in two different locations on the power system will result in two different voltage distortion values. Recognition of this fact is the

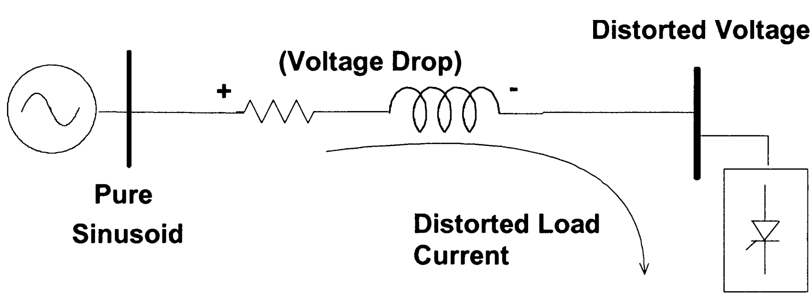

FIGURE 23-33 Harmonic currents flowing through the system impedance results in harmonic voltages at the load.

basis for the division of responsibilities for harmonic control that are found in standards such as IEEE Std 519-1992:

- The control over the amount of harmonic current injected into the system takes place at the end-use application,
- Assuming the harmonic current injection is within reasonable limits, the control over the voltage distortion is exercised by the entity having control over the system impedance, which is often the utility.

One must be careful when describing harmonic phenomena to understand that there are distinct differences between the causes and effects of harmonic voltages and currents. The use of the term harmonics should be qualified accordingly. By popular convention in the power industry, the majority of time the term is used by itself when referring to load apparatus, the speaker is referring to the harmonic currents. When referring to the utility system, the voltages are generally the subject.

23.5.4 Power System Quantities under Nonsinusoidal Conditions

Traditional power system quantities such as rms, power (reactive, active, apparent), power factor, and phase sequences are defined for the fundamental frequency context in a pure sinusoidal condition. In the presence of harmonic distortion the power system no longer operates in a sinusoidal condition, and unfortunately many of the simplifications power engineers use for the fundamental frequency analysis do not apply. Therefore, these quantities must be redefined.

23.5.5 RMS Values of Voltage and Current

In a sinusoidal condition both the voltage and current waveforms contain only the fundamental frequency component, thus the rms values can be expressed simply as

$$V_{\mathrm{rms}} = \frac{1}{\sqrt{2}} V_1 \qquad \text{and} \qquad I_{\mathrm{rms}} = \frac{1}{\sqrt{2}} I_1. \tag{23-2}$$

where V_1 and I_1 are the amplitude of voltage and current waveforms, respectively. The subscript 1 denotes quantities in the fundamental frequency. In a nonsinusoidal condition a harmonically distorted waveform is made up of sinusoids of harmonic frequencies with different amplitudes as shown in Fig. 23-2. The rms values can of the waveforms are computed as the square root of the sum of rms squares of all individual components, that is,

$$V_{\mathrm{rms}} = \sqrt{\sum_{h=1}^{h_{\max}} \left(\frac{1}{\sqrt{2}} V_h\right)^2} = \frac{1}{\sqrt{2}} \sqrt{V_1^2 + V_2^2 + V_3^2 + \cdots + V_{h_{\max}}^2}, \tag{23-3}$$

$$I_{\mathrm{rms}} = \sqrt{\sum_{h=1}^{h_{\max}} \left(\frac{1}{\sqrt{2}} I_h\right)^2} = \frac{1}{\sqrt{2}} \sqrt{I_1^2 + I_2^2 + I_3^2 + \cdots + I_{h_{\max}}^2}, \tag{23-4}$$

where V_h and I_h are the amplitude of a waveform at the harmonic component h. In the sinusoidal condition, harmonic components of V_h and I_h are all zero, and only V_1 and I_1 remain. Equations (23-3) and (23-4) simplify to Eq. (23-2).

23.5.6 Active Power

The *active power*, P, is also commonly referred to as the average power, real power, or true power. It represents useful power expended by loads to perform real work, that is, to convert electric energy to other form of energy. Real work performed by an incandescent light bulb is to convert electric energy into light and heat. In electric power, real work is performed for the portion of the current that is in phase with the voltage. No real work will result, from the portion where the current is not in phase with the voltage. The active power is the rate at which energy is expended, dissipated or consumed by the load, and is measured in units of watts (W). P can be computed by averaging the product of the instantaneous voltage and current, that is,

$$P = \frac{1}{T}\int_0^T v(t)i(t)dt. \tag{23-5}$$

The above equation is valid for both sinusoidal and nonsinusoidal conditions. For sinusoidal condition, $I_{1\text{rms}}$ resolves to the familiar form,

$$P = \frac{V_1 I_1}{2}\cos\theta_1 = V_{1\text{rms}} I_{1\text{rms}}\cos\theta_1 = S\cos\theta_1, \tag{23-6}$$

where θ_1 is the phase angle between voltage and current at the fundamental frequency. Equation 23-6 indicates that the average active power is a function only of the fundamental frequency quantities. In the nonsinusoidal case, the computation of the active power must include contribution from all harmonic components, thus it is the sum of active power at each harmonic. Furthermore, because the voltage distortion is generally very low on power systems (less than 5%), Eq. (23-6) is a good approximation regardless of how distorted the current is. This approximation cannot be applied when computing the apparent and reactive power. These two quantities are greatly influenced by the distortion. The apparent power, S, is a measure of the potential impact of the load on the thermal capability of the system. It is proportional to the rms of the distorted current and it computation is straightforward, although slightly more complicated than the sinusoidal case. Also, many current probes can now directly report the true rms value of a distorted waveform.

23.5.7 Reactive Power

The *reactive power* is a type of power that does no real work and is generally associated with reactive elements (inductors and capacitors). For example, the inductance of a load such as a motor causes the load current to lag behind the voltage. Power appearing across the inductance sloshes back and forth between the inductance itself and the power system source producing no net work. For this reason it is called imaginary or reactive power since no power is dissipated or expended. It is expressed in units of volt-ampere-reactive or var. In the sinusoidal case, the reactive power is simply defined as

$$Q = S\sin\theta_1 = \frac{V_1 I_1}{2}\sin\theta_1 = V_{1\text{rms}} I_{1\text{rms}}\sin\theta_1 \tag{23-7}$$

which is the portion of power in quadrature with the active power shown in Eq. (23-6). Figure 23-34 summarizes the relationship between P, Q, and S in sinusoidal condition.

There is some disagreement among harmonics analysts on how to define Q in the presence of harmonic distortion. If it were not for the fact that many utilities measure Q and compute demand billing from the power factor computed by Q, it might be a moot point. It is more important to determine P and S; P defines how much active power is being consumed while S defines the capacity of the power system required to deliver P. Q is not actually very useful by itself. However, Q_1 the traditional reactive power component at fundamental frequency, may be used to size shunt capacitors.

The reactive power, when distortion is present, has another interesting peculiarity. In fact, it may not be appropriate to call it reactive power. The concept of var flow in the power system is deeply ingrained in the minds of most power engineers. What many do not realize is that this concept is valid only in the sinusoidal steady state. When distortion is present, the component of S that remains after P is taken out, is not conserved—that is, it does not sum to zero at a node. Power quantities are presumed to flow around the system in a conservative manner.

This does not imply that P is not conserved or that current is not conserved because the conservation of energy and Kirchoff's current laws are still applicable for any waveform. The reactive components actually sum in quadrature (square root of the sum of the squares). This has prompted some analysts to propose that Q be used to denote the reactive components that are conserved and introduce

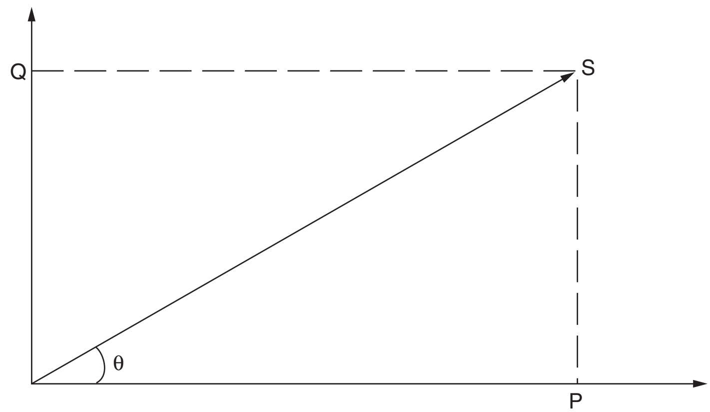

FIGURE 23-34 Relationship between P, Q, and S in sinusoidal condition.

a new quantity for the components that are not. Many call this quantity D, for *distortion power* or, simply, *distortion voltamperes*. It has units of voltamperes, but it may not be strictly appropriate to refer to this quantity as *power*, because it does not flow through the system as power is assumed to do. In this concept, Q consists of the sum of the traditional reactive power values at each frequency. D represents all cross products of voltage and current at different frequencies, which yield no average power. P, Q, D, and S are related as follows, using the definitions for S and P above as a starting point:

$$S = \sqrt{P^2 + Q^2 + D^2}$$
$$Q = \sum_k V_k I_k \sin \theta_k. \tag{23-8}$$

Therefore, D can be determined after S, P, and Q by

$$D = \sqrt{S^2 - P^2 - Q^2}. \tag{23-9}$$

Some prefer to use a three-dimensional vector chart to demonstrate the relationships of the components as shown in Fig. 23-35. P and Q contribute the traditional sinusoidal components to S while D represents the additional contribution to the apparent power by the harmonics.

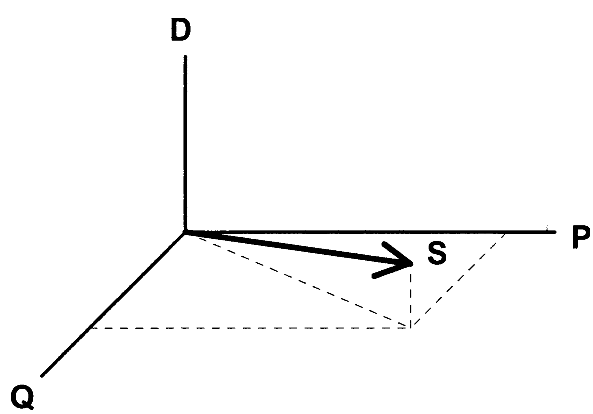

FIGURE 23-35 Relationship of components of the apparent power.

23.5.8 Power Factor

A *power factor* is a ratio of useful power to perform real work (active power) to the power supplied by a utility (apparent power), that is,

$$PF = \frac{P}{S} \tag{23-10}$$

In other words, the power factor ratio measures the percentage of power expended for its intended use. Power factor ranges from zero to unity. A load with power factor of 0.9 lagging denotes that the load can effectively expend 90% of the apparent power supplied (VA) and convert it to perform useful work (*W*). The term "lagging" denotes that the fundamental current lags behind the fundamental voltage by 25.84°.

In the sinusoidal case there is only one phase angle between the voltage and the current (since only the fundamental frequency is present), the power factor can be computed as the cosine of the phase angle and is commonly referred as the *displacement power factor*,

$$PF = \frac{P}{S} = \cos\theta. \tag{23-11}$$

In the nonsinusoidal case the power factor cannot be defined as the cosine of the phase angle as in Eq. (23-11). The power factor that takes into account contribution from all active power both fundamental and harmonic frequencies is known as the *true power factor*. The true power factor is simply the ratio of total active power for all frequencies to the apparent power delivered by the utility as shown in Eq. (23-10).

Power quality monitoring instruments now commonly report both displacement and true power factors. Many devices such as switch-mode power supplies and PWM adjustable-speed drives have a near-unity displacement power factor, but the true power factor may be 0.5 to 0.6. An ac-side capacitor will do little to improve the true power factor in this case because is Q_1 zero. In fact, if it results in resonance, the distortion may increase, causing the power factor to degrade. The true power factor indicates how large the power delivery system must be built to supply a given load. In this example, using only the displacement power factor would give a false sense of security that all is well.

The bottom line is that distortion results in additional current components flowing in the system that do not yield any net energy except that they cause losses in the power system elements they pass through. This requires the system to be built to a slightly larger capacity to deliver the power to the load than if no distortion were present.

23.5.9 Harmonic Phase Sequence

Power engineers have traditionally used symmetrical components to help describe 3-phase system behavior. The 3-phase system is transformed into three single-phase systems that are much simpler to analyze. The method of symmetrical components can be employed for analysis of the system's response to harmonic currents provided care is taken not to violate the fundamental assumptions of the method.

The method allows any unbalanced set of phase currents (or voltages) to be transformed into three balanced sets. The *positive sequence* set contains three sinusoids displaced 120° from each other, with the normal A-B-C phase rotation (e.g., 0°, –120°, 120°). The sinusoids of the *negative-sequence* set are also displaced 120°, but have opposite phase rotation (A-C-B, e.g., 0°, 120°, –120°). The sinusoids of the *zero sequence* are in phase with each other (e.g., 0, 0, 0).

In a perfect balanced 3-phase system, the harmonic phase sequence can be determined by multiplying the harmonic number *h* with the normal positive sequence phase rotation. For example, for the second harmonic, $h = 2$, produces $2 \times (0°, -120°, -120°)$ or $(0°, 120°, -120°)$ which is the negative sequence. For the third harmonic, $h = 3$, produces $3 \times (0°, -120°, -120°)$ or $(0°, 0°, 0°)$ which is the zero sequence. Phase sequence for all other harmonic orders can be determined in the same fashion. Since a distorted waveform in power systems contains only odd harmonic components (see Sec. 23.5.1), only odd harmonic phase sequence rotations are summarized below:

- Harmonics of order $h = 1, 7, 13, \ldots$ are purely positive sequence.
- Harmonics of order $h = 5, 11, 17, \ldots$ are purely negative sequence.
- Triplens ($h = 3, 9, 15, \ldots$) are purely zero sequence.

23.5.10 Triplen Harmonics

Triplen harmonics are the odd multiples of the third harmonic ($h = 3, 9, 15, 21, \ldots$). They deserve special consideration because the system response is often considerably different for triplens than for the rest of the harmonics. Triplens become an important issue for grounded-wye systems with current flowing on the neutral. Two typical problems are overloading the neutral and telephone interference. One also hears occasionally of devices that misoperate because the line-to-neutral voltage is badly distorted by the triplen harmonic voltage drop in the neutral conductor.

For the system with perfectly balanced single-phase loads illustrated in Fig. 23-36, an assumption is made that fundamental and third harmonic components are present. Summing the currents at node N, the fundamental current components in the neutral are found to be zero, but the third harmonic components are three times the phase currents because they naturally coincide in phase and time.

23.5.11 Triplen Harmonics in Transformers

Transformer winding connections have a significant impact on the flow of triplen harmonic currents from single-phase nonlinear loads. Two cases are shown in Fig. 23-37. In the wye-delta transformer (top), the triplen harmonic currents are shown entering the wye side. Since they are in phase, they add in the neutral. The delta winding provides ampere-turn balance so that they can flow, but they remain trapped in the delta and do not show up in the line currents on the delta side. When the currents are balanced, the triplen harmonic currents behave exactly as zero-sequence currents, which is precisely what they are. This type of transformer connection is the most common employed in utility

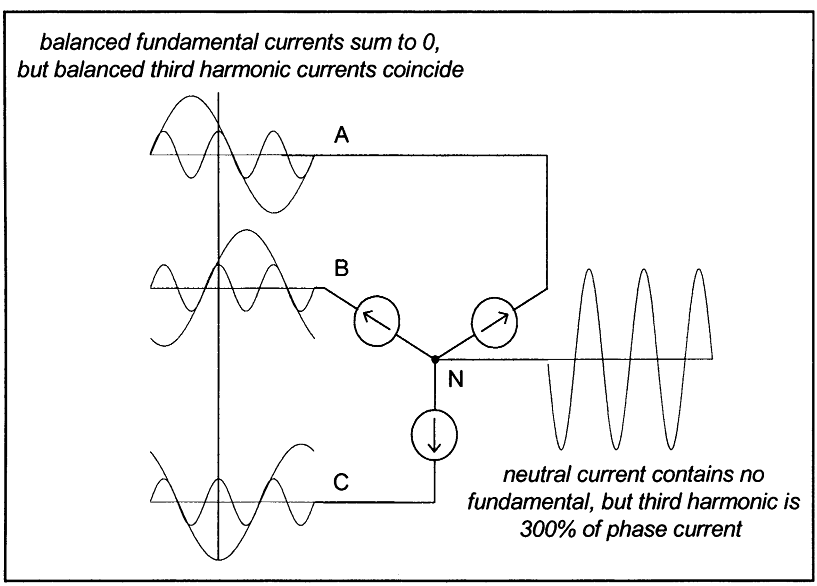

FIGURE 23-36 High neutral currents in circuits serving single-phase nonlinear loads.

distribution substations with the delta winding connected to the transmission feed.

Using grounded-wye windings on both sides of the transformer (bottom) allows balanced triplens to flow from the low voltage system to the high voltage system unimpeded. They will be present in equal proportion on both sides. Many loads in the United States are served in this fashion.

Some important implications of this related to power quality analysis are

1. Transformers, particularly the neutral connections, are susceptible to overheating when serving single phase loads on the wye side that have high third harmonic content.
2. Measuring the current on the delta side of a transformer will not show the triplens and, therefore, not give a true idea of the heating the transformer is being subjected to.

   The flow of triplen harmonic currents can be interrupted by the appropriate isolation transformer connection.
3. Removing the neutral connection in one or both wye windings, blocks the flow of triplen harmonic current. There is no place for ampere-turn balance. Likewise, a delta winding blocks the flow from the line. One should note that three-legged core transformers behave as if they have a "phantom" delta tertiary winding. Therefore, a wye-wye with only one neutral point grounded will still be able to conduct the triplen harmonics from that side.

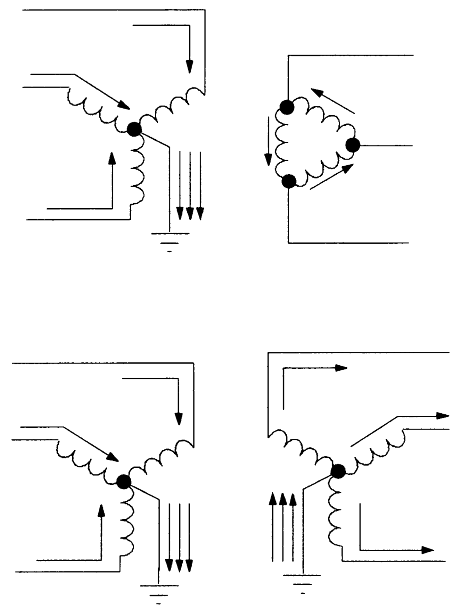

FIGURE 23-37 Flow of third harmonic current in 3-phase transformers.

These rules about triplen harmonic current flow in transformers apply only to balanced loading conditions. When the phases are not balanced, currents of normal triplen harmonic frequencies may very well show up where they are not expected. The normal mode for triplen harmonics is to be zero sequence. During imbalances, triplen harmonics may have positive or negative sequence components too.

One notable case of this is a 3-phase arc furnace. The furnace is nearly always fed by a delta-delta connected transformer to block the flow of the zero sequence currents, as shown in Fig. 23-8. Thinking that third harmonics are synonymous with zero sequence, many engineers are surprised to find substantial third harmonic current present in large magnitudes in the line current. However, during scrap meltdown, the furnace will frequently operate in an unbalanced mode with only two electrodes carrying current. Large third harmonic currents can then freely circulate in these two phases just as a single-phase circuit. However, they are not zero sequence currents. The third harmonic currents are equal amounts of positive and negative sequence currents. But to the extent that the system is mostly balanced, triplens mostly behave in the manner described.

23.5.12 Total Harmonic Distortion

The total harmonic distortion (THD) is a measure of the *effective value* of the harmonic components of a distorted waveform. That is, the potential heating value of the harmonics relative to the fundamental. This index can be calculated for either voltage or current:

$$\mathrm{THD} = \frac{\sqrt{\sum_{h>1}^{h_{\max}} M_h^2}}{M_1} \tag{23-12}$$

where M_h is the rms value of harmonic component h of the quantity M. The rms value of a distorted waveform is the square root of the sum of the squares as shown in Eq. (23-3) and (23-4). THD is related to the rms value of the waveform as follows:

$$\mathrm{RMS} = \sqrt{\sum_{h=1}^{h_{\max}} M_h^2} = M_1 \cdot \sqrt{1 + THD^2} \tag{23-13}$$

THD is a very useful quantity for many applications, but its limitations must be realized. It can provide a good idea of how much extra heat will be realized when a distorted voltage is applied across a resistive load. Likewise, it can give an indication of the addition losses caused by the current flowing through a conductor. However, it is not a good indicator of the voltage stress within a capacitor because that is related to the peak value of the voltage wave form, not its heating value. The THD index is most often used to describe voltage harmonic distortion. Harmonic voltages are almost always referenced to the fundamental value of the waveform at the time of the sample. Because voltage varies only a few percent, the voltage THD is nearly always a meaningful number.

23.5.13 Total Demand Distortion

Current distortion levels can be characterized by a THD value, as described above, but this can often be misleading. A small current may have a high THD but not be a significant threat to the system For example, many adjustable speed drives will exhibit high THD values for the input current when they are operating at very light loads. This is not necessarily a significant concern because the magnitude of harmonic current is low, even though its relative current distortion is high.

Some analysts have attempted to avoid this difficulty by referring THD to the fundamental of the peak demand load current rather than the fundamental of the present sample. This is called *total demand distortion* (*TDD*), and serves as the basis for the guidelines in IEEE STD 519-1992. It is defined as follows:

$$\mathrm{TDD} = \frac{\sqrt{\sum_{h=2}^{h_{\max}} I_h^2}}{I_L} \tag{23-14}$$

where I_L is the peak, or maximum demand load current at the fundamental frequency component measured at the point of common coupling (PCC). There are two ways to measure I_L. With a load already in the system, it can be calculated as the average of the maximum demand current for the preceding 12 months. The calculation can simply be done by averaging the 12-month peak demand readings. For a new facility, I_L has to be estimated based on the predicted load profiles.

23.5.14 System Response Characteristics

In analyzing harmonic problems, the response of the power system is equally as important as the sources of harmonics. In fact, power systems are quite tolerant of the currents injected by harmonic-producing loads unless there is some adverse interaction with the impedance of the system. Identifying the sources is only half the job of harmonic analysis. The response of the power system at each harmonic frequency determines the true impact of the nonlinear load on harmonic voltage distortion.

There are three primary variables affecting the system response characteristics, that is, the system impedance, the presence of capacitor bank, and the amount of resistive loads in the system.

23.5.15 System Impedance

At the fundamental frequency, power systems are primarily inductive, and the equivalent impedance is sometimes called simply the short-circuit reactance. Capacitive effects are frequently neglected on utility distribution systems and industrial power systems. One of most frequently-used quantities in the analysis of harmonics on power systems is the short-circuit impedance to the point on a network at which a capacitor is located. If not directly available, it can be computed from short-circuit study results that give either the short-circuit *MVA* or the short-circuit current as follows:

$$\begin{aligned} Z_{SC} &= R_{SC} + jX_{SC} \\ &= \frac{kV^2}{MVA_{SC}} = \frac{kV}{\sqrt{3}I_{SC}} \end{aligned} \tag{23-15}$$

where Z_{SC} = Short-circuit impedance
R_{SC} = Short-circuit resistance
X_{SC} = Short-circuit reactance
KV = Phase-to-phase voltage, kV
MVA_{SC} = 3-phase short-circuit, MVA
I_{SC} = Short-circuit current, A

Z_{SC} is a phasor quantity, consisting of both resistance and reactance. However, if the short-circuit data contains no phase information, one is usually constrained to assuming that the impedance is purely reactive. This is a reasonably good assumption for industrial power systems for buses close to the mains and for most utility systems. When this is not the case, an effort should be made to determine a more realistic resistance value because that will affect the results once capacitors are considered.

The inductive reactance portion of the impedance changes linearly with frequency. One common error made by novices in harmonic analysis is to forget to adjust the reactance for frequency. The reactance at the *h*-th harmonic is determined from the fundamental-impedance reactance, X_1, by

$$X_h = hX_1 \tag{23-16}$$

In most power systems, one can generally assume that the resistance does not change significantly when studying the effects of harmonics less than the ninth. For lines and cables, the resistance varies approximately by the square root of the frequency once skin effect becomes significant in the conductor at a higher frequency. The exception to this rule is with some transformers. Because of stray eddy current losses, the apparent resistance of larger transformers may vary almost proportionately with the frequency. This can have a very beneficial effect on damping of resonance as shown later. In smaller transformers, less than 100 kVA, the resistance of the winding is often so large relative to the other impedances that it swamps out the stray eddy current effects and there is little change in the total apparent resistance until the frequency reaches about 500 Hz. Of course, these smaller transformers may have an *X*/*R* ratio of 1.0 to 2.0 at fundamental frequency while large substation transformers might typically be 20 to 30. Therefore, if the bus that is being studied is dominated by transformer impedance rather than line impedance, the system impedance model should be considered more carefully. Neglecting the resistance will generally give a conservatively high prediction of the harmonic distortion.

At utilization voltages, such as industrial power systems, the equivalent system reactance is often dominated by the service transformer impedance. A good approximation for X_{SC} may be based on the impedance of the service entrance transformer only

$$X_{SC} \approx X_{tx} \tag{23-17}$$

While not precise, this is generally at least 90% of the total impedance and is commonly more. This is usually sufficient to evaluate whether or not there will be a significant harmonic resonance problem. Transformer impedance in ohms can be determined from the percent impedance, Z_{tx}, found on the nameplate by

$$X_{tx} = \left(\frac{kV^2}{MVA_{3\phi}}\right) \times Z_{tx}(\%) \tag{23-18}$$

where $MVA_{3\phi}$ is the kVA rating of the transformer. This assumes that the impedance is predominantly reactive. For example for a 1500 kVA, 6% transformer, the equivalent impedance on the 480 V side is

$$X_{tx} = \left(\frac{kV^2}{MVA_{3\phi}}\right) \times Z_{tx}(\%) = \left(\frac{0.480^2}{1.5}\right) \times 0.06 = 0.0092\Omega$$

23.5.16 Capacitor Impedance

Shunt capacitors, either at the customer location for power factor correction, or on the distribution system for voltage control, dramatically alter the system impedance variation with frequency. Capacitors do not create harmonics, but severe harmonic distortion can sometimes be attributed to their presence. While the reactance of inductive components increases proportionately to frequency, capacitive reactance, X_c, decreases proportionately:

$$X_C = \frac{1}{2\pi fC} \tag{23-19}$$

where C is the capacitance in farads. This quantity is seldom readily available for power capacitors, which are rated in terms of kvar or Mvar at a given voltage. The equivalent line-to-neutral capacitive reactance at fundamental frequency for a capacitor bank can be determined by

$$X_c = \frac{kV^2}{\mathrm{M}var} \tag{23-20}$$

For 3-phase banks, use phase-to-phase voltage and the 3-phase reactive power rating. For single-phase units, use the can voltage rating and the reactive power rating. For example, for a 3-phase, 1200 kvar, 13.8-kV capacitor bank, the positive-sequence reactance in ohms would be

$$X_c = \frac{kV^2}{\mathrm{M}var} = \frac{13.8^2}{1.2} = 158.7\Omega$$

23.5.17 Parallel and Series Resonance

All circuits containing both capacitance and inductance have one or more natural resonant frequencies. When one of these frequencies corresponds to an exciting frequency being produced by nonlinear loads, harmonic resonance can occur. Voltage and current will be dominated by the resonant frequency and can be highly distorted. Thus, the response of the power system at each harmonic frequency determines the true impact of the nonlinear load on harmonic voltage distortion.

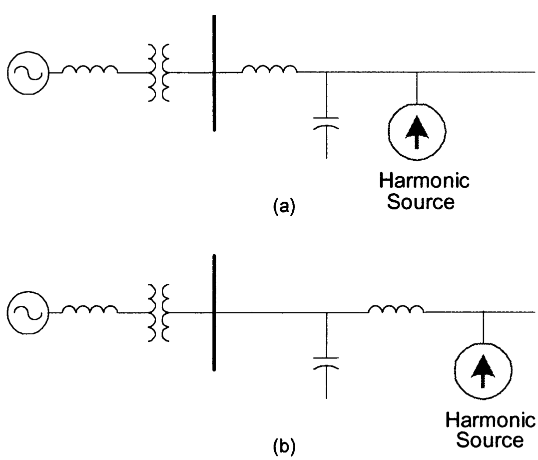

FIGURE 23-38 Examples of (*a*) parallel and (*b*) series resonance.

Resonance can cause nuisance tripping of sensitive electronic loads and high harmonic currents in feeder capacitor banks. In severe cases, capacitors produce audible noise, and they sometimes bulge. To better understand resonance, consider the simple parallel and series cases shown in the one-line diagrams of Fig. 23-38. Parallel resonance occurs when the power system presents a parallel combination of power system inductance and power factor correction capacitors at the nonlinear load. The product of harmonic impedance and injection current produces high harmonic voltages. Series resonance occurs when the system inductance and capacitors are in series, or nearly in series, with respect to the nonlinear load point. For parallel resonance, the highest voltage distortion is at the nonlinear load. However, for series resonance, the highest voltage distortion is at a remote point, perhaps miles away or on an adjacent feeder served by the same substation transformer. Actual feeders can have five or ten shunt capacitors each, so many parallel and series paths exist, making computer simulations necessary to predict distortion levels throughout the feeder.

In the simplest parallel resonant cases, such as an industrial facility where the system impedance is dominated by the service transformer, shunt capacitors are located inside the facility, and distances are small. In these cases, the simple parallel scenario shown in Fig. 23-38*a* often applies.

23.5.18 Effects of Resistance and Resistive Load

Determining that the resonant harmonic aligns with a common harmonic source is not always cause for alarm. The damping provided by resistance in the system is often sufficient to prevent catastrophic voltages and currents. Figure 23-39 shows the parallel resonant circuit impedance characteristic for various amounts of resistive load in parallel with the capacitance. As little as 10% resistive loading can have a significant beneficial impact on peak impedance. Likewise, if there is a significant length of lines or cables between the capacitor bus and the nearest upline transformer, the resonance will be suppressed. Lines and cables can add a significant amount of the resistance to the equivalent circuit.

Loads and line resistances are the reasons why catastrophic harmonic problems from capacitors on utility distribution feeders are seldom seen. That is not to say that there will not be any harmonic problems due to resonance, but that the problems will generally not cause physical damage to the electrical system components. The most troublesome resonant conditions occur when capacitors are installed on substations buses, either utility substations or in industrial facilities. In these cases, where the transformer dominates the system impedance and has a high X/R ratio, the relative resistance is low and the corresponding parallel resonant impedance peak is very sharp and high. This is a common cause of capacitor failure, transformer failure, or the failure of load equipment.

It is a misconception that resistive loads damp harmonics because in the absence of resonance, loads of any kind will have little impact on the harmonic currents and resulting voltage distortion. Most of the current will flow back into the power source. However, it is very appropriate to say that resistive loads will damp *resonance*, which will lead to a significant reduction in the harmonic distortion.

23.5.19 Harmonic Impacts

Harmonics have a number of undesirable effects on power system components and loads. These fall into two basic categories: short-term and long-term. Short-term effects are usually the most noticeable and are related to excessive voltage distortion. On the other hand, long-term effects often go

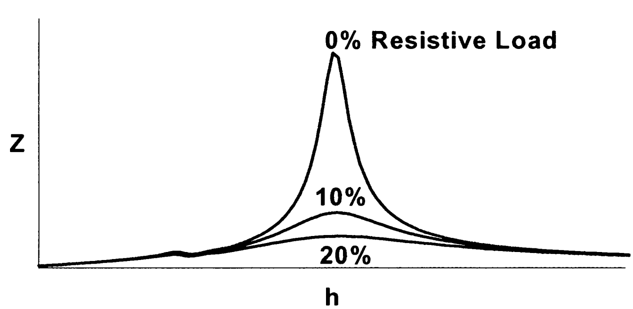

FIGURE 23-39 Effect of resistive loads on parallel resonance.

undetected and are usually related to increased resistive losses or voltage stresses. Short-term effects can cause nuisance tripping of sensitive loads. Some computer-controlled loads are sensitive to voltage distortion. For example, one documented case showed that a voltage distortion of 5.5% regularly shut down computerized lathes at a large pipe company heat treatment operation. While voltage distortions of 5% are not usually a problem, voltage distortions above 10% will almost always cause significant nuisance tripping or transformer overheating.

Harmonics can degrade meter accuracy. This is especially true with common single-phase induction-disk meters. In general, the meter spins 1% to 2% faster when a customer produces harmonic power. However, the greater issue in metering is the question of how active power, and especially reactive power, should be defined and measured when distortion is present. Debate on these definitions continues today.

Blown capacitor fuses and failed capacitor cans are also attributed to harmonics. Harmonic voltages produce excessive harmonic currents in capacitors because of the inverse relationship between capacitor impedance and frequency. Voltage distortions of 5% and 10% can easily increase rms currents by 10% to 50%. Capacitors may also fail because of overvoltage stress on dielectrics. A 10% harmonic voltage for any harmonic above the third increases the peak voltage by approximately 10% because the peak of the harmonic usually coincides, or nearly coincides, with the peak of the fundamental voltage.

Harmonics can also cause transformer overheating. This usually occurs when a dedicated transformer serves only one large nonlinear load. In such a situation, the transformer must be derated accordingly. Derating to 0.80 of nameplate kVA is common.

Overloaded neutrals appear to be the most common problems in commercial buildings. In a 3-phase, four-wire system, the sum of the 3-phase currents returns through the neutral conductor. Positive and negative sequence components add to zero at the neutral point, but zero sequence components are additive at the neutral.

23.5.20 Control of Harmonics

There are two common causes of harmonic problems are

- Nonlinear loads injecting excessive harmonic currents
- The interaction between harmonic currents and the system frequency response

When harmonics become a problem, commonly-employed solutions are

- Limit harmonic current injection from nonlinear loads. Transformer connections can be employed to reduce harmonics in a 3-phase system by using parallel delta-delta and wye-delta transformers to yield net 12-pulse operation, or delta connected transformers to block triplen harmonics.
- Modify system frequency response to avoid adverse interaction with harmonic currents. This can be done by feeder sectionalizing, adding or removing capacitor banks, changing the size of the capacitor banks, adding shunt filters, or adding reactors to detune the system away from harmful resonances.
- Filter harmonic currents at the load or on the system with shunt filters, or try to block the harmonic currents produced by loads. There are a number of devices to do this. Their selection is largely dependent on the nature of the problems encountered. Solutions can be as simple as an in-line reactor (i.e., a choke) as in PWM-based adjustable speed drive applications, or as complex as an active filter.

23.6 ELECTRICAL POWER RELIABILITY AND RECENT BULK POWER OUTAGES

23.6.1 Electric Power Distribution Reliability—General

The term *reliability* in the utility context usually refers to the amount of time end users are totally without power for an extended period of time (i.e., a sustained interruption). Definitions of what constitutes a sustained interruption vary among utilities in the range of 1 to 5 min. This is what many utilities refer to as an "outage." Current power quality standards efforts are leaning toward calling any interruption of power for longer than 1 min, a sustained interruption. In any case, reliability is affected by the permanent faults on the system that must be repaired before service can be restored.

23.6.2 Electric Power Distribution Reliability Indices

Most commonly used reliability indices for utility distribution systems are defined as follows:

- SAIFI: System Average Interruption Frequency Index

  SAIFI represents the average interruption frequency experienced by customers served in the system over a given period of time. It is computed as follows:

$$\text{SAIFI} = \frac{\text{(no. of customer interrupted)(no. of interruption)}}{\text{total no. of customers}}$$

- SAIDI: System Average Interruption Duration Index

  SAIDI represents the average interruption duration experienced by customers in the system over a given period of time.

$$\text{SAIDI} = \frac{\sum \text{(no. of customer affected)(duration of outage)}}{\text{total no. of customers}}$$

- CAIFI: Customer Average Interruption Frequency Index

  CAIFI represents average interruption frequency for affected customers. Customers not experiencing interruption are not included in the calculation.

$$\text{CAIFI} = \frac{\text{total no. of customer interruptions}}{\text{total no. of customers affected}}$$

- CAIDI: Customer Average Interruption Duration Index

  CAIDI represents the average interruption duration for customers experiencing interruptions. In other words, this is the average restoration time for affected customers.

$$\text{CAIDI} = \frac{\sum \text{(customer interruption durations)}}{\text{total no. of customers interruptions}}$$

- ASAI: Average System Availability Index

  ASAI represents the average system availability over a given observation period, which is usually a year (or 8760 hours). The index is given in percent.

$$\text{ASAI} = \frac{\sum \text{customer hours service availability}}{\text{customer hours service demand}}$$

23.6.3 Major Bulk Electric Power Outages

Since the electric power industry was born in the early twentieth century, there have been several notable major bulk power outages. Most common causes of these outages are errors in protective device system design, overgrown vegetation, loss of system awareness due to failure of alarm systems, and a combination of unexpected events, whether they are natural and man made. Summary of these bulk power outages are complied from various sources and presented in the next paragraphs.

23.6.4 Great Northeast Blackout of 1965

The 1965 power outage started on November 9 at about 5:15 P.M. in Ontario, Canada. It cascaded down through the power system to the majority of New York, Connecticut, Massachusetts, Rhode Island, and some portions of northern Pennsylvania, and New Jersey. They were about 30 million customers out of service for up to 13 h. The power outage left 20 GW of load demand unserved. The outage was triggered by a backup protectively relay in opening one of five 230-kW lines delivering power from the Adam Beck Station No. 2 to the Toronto load area. System operators were not aware that the backup relay was set to take the line out of service when the line loading exceeded 375 MW. This relay setting was below the unusually high line loadings of recent months. Higher than normal line loadings was imposed due to higher than normal import from the United States to cover nearby Lakeview power plant (west of Toronto) outage. Upon opening the 230-kV line, the remaining four 230-kV lines were also tripped out successively within $2^1/_2$ s. Subsequently, two key east–west 345-kV lines between Rochester and Syracuse tripped out due to line instability. Several lower voltage lines tripped open along with 5 of 11 generation units at the St. Lawrence (Massena) Station. Losses of major transmission lines caused 10 generators at Adam Beck Station to shut down due to low governor oil pressure. By 5:30 P.M., the majority of northeast was without power. The service was, however, restored by 4:44 A.M. the next day in Manhattan [18].

23.6.5 New York Blackout of 1977

The event started on July 13 at about 8:37 P.M., when a lightning stroke caused a phase B to ground fault on both of a double-circuit 345-kV transmission line between Buchanan South and Millwood West Substations [18,19,21]. The tripping of circuit breakers at Buchanan South Circuit rings isolated Indian Point No. 3 generating unit without a transmission path to any load. The plant tripped of line and shut down causing a generation loss of 883 MW. A coordination error in the protective system played a critical role in the subsequent chain of events in which a transfer trip signal to Ladentown was initiated to open the 345-kV line from Buchanan South to Ladentown. A subsequent lighting stroke also caused a trip out of two more 345-kV lines between Sprain Brook and Buchanan North, and Sprain Brook and Millwood West. The later was restored to service in about 2 s. However, Sprain Brook to Buchanan North 345-kV was out of service. Losses of key transmission lines eventually forced the electrical system to separate and collapse. The power outage affected 9 million people. However, it was limited to New York City alone. Unlike the 1965 blackout, the 1977 event was marred by violence and looting [20].

Timeline of key events in the total collapse of the ConEd system [19,21]:

- At 8:37:17 P.M., July 13, 1997, two 345-kV lines connecting Buchanan South to Millwood West were each subjected to a phase B fault to ground as a result of a severe lightning stroke.
- The tripping of circuit breakers at the Buchanan South ring bus, isolated the Indian Point No. 3 generating unit from any load, and the unit tripped for a loss of 883 MW.
- Loss of the ring bus isolated the 345-kV tie to Ladentown, which had been importing 427 MW, with a total loss now of 1310 MW.
- At 8:55:53 P.M., about $18^1/_2$ minutes after the first incident, a severe lightning stroke caused the trip-out of two 345-kV lines, which connect Sprain Brook to Buchanan North, and Sprain Brook to Millwood West. These two 345-kV lines share common towers between Millwood West and Sprain Brook. One line (Millwood West to Sprain Brook) was restored to service in about 2 s. The failure of the other line to reclose isolated the last ConEd interconnection to the northwest.
- The resulting surge of power from the northwest, caused the trip-out of the line between Pleasant Valley and Millwood West (a bent contact on one of the relays at Millwood West caused the improper action).
- At 9:19:11 P.M., a 345-kV line, Leeds Substation to Pleasant Valley tripped as a result of a phase B fault to ground (fault probably caused by line sag to a tree because of the excessive overload imposed on the line).

- At 9:19:53 P.M., the 345-kV/138-kV transformer at Pleasant Valley tripped on overcurrent relay and left ConEd with three remaining interconnections.
- At 9:22:11 P.M., the Jamaica/Valley Stream tie was opened manually by the Long Island Lighting Co. system operator after obtaining the approval of the pool dispatcher.
- About 7 min later, the tap-changing mechanism failed on the Goethals phase-angle regulating transformer resulting in the trip of the Linden/Goethals tie to PJM, which was carrying 1150 MW to ConEd.
- The two remaining external 138-kV ties to ConEd tripped on overload isolating the ConEd system.

23.6.6 The Northwestern Blackout of July 1996

This outage occurred on July 2 at about 2:24 P.M. when a tree fault tripped a 345-kV taking power from Jim Bridger power plant in southwest Wyoming to southeast Idaho [17]. Protective devices detected the fault and de-energized the line. However, due to a protection coordination error, a parallel 345-kV line was also tripped. The loss of two 345-kV line severely limited power transfers from Jim Bridger plant causing generator protective devices to trip two 500-MW generators to maintain the system stability. With two generators out, frequency in the entire western interconnection began to decline forcing some customers out of service. This move was not successful and the system disintegrated into five islands. About 2 million customers were interrupted for up to several hours with about 11,850 MW of loss of load demand.

23.6.7 The Northwestern Blackout of August 1996

This blackout occurred on August 10 when Keeler-Allston 500-kV transmission line sagged into a grove of trees [17]. Prior to the disturbance, the Northwest area was importing about 2300 MW from Canada due to excellent hydroelectric conditions that lead to high electricity transfers. This and other conditions, that is, hot weather, maintenance outage of a transformer that connects a static var compensator to a 500-kV line in Portland, and/or failure to trim trees, lead to a cascading outage. A series tree fault disturbances finally broke the western interconnection area into four islands and interrupting services to 7.5 million customers for up to 9 h.

23.6.8 The Great Northeastern Power Blackout of 2003 [22, 23]

This outage on August 14, 2003 is by far the largest and most severe among all major outages. It affected 50 million customers for up to 2 days. The area affected was over 9266-mi [2] covering two Canadian provinces and eight northeastern U.S. states. The outage caused an estimated of $4 to $8 billion in lost economic activity.

The outage was preceded by a computer software abnormal operation, a series of generator tripping, and line outages. This series of events is considered as a precursor to the cascading outage. MISO's (Midwest Independent Service Operator) state estimator software solution did not converge and produced a solution with a high mismatch due to an outdated input data in the state estimator. Eastlake No. 5 generating unit tripped along with two other units (Conesville and Greenwood) causing a severe shortage in reactive power supply. Adequate reactive power supply is an important requirement high voltage long distance electric power transmission. At about 2:02 P.M., Stuart–Atlanta 345 kV in southwestern Ohio tripped due to contact with trees causing a short circuit to ground and locked out. This situation was exacerbated by lost of key alarm functions in FirstEnergy's (Ohio) control room. The controller also lost a series of other important computer functions. Unfortunately, FirstEnergy operators were unaware of computer failures thus they lost situational awareness of their system.

Precipitating events that lead to the cascading outage began around 3:00 P.M., when three key 345-kV transmission lines into northern Ohio from eastern Ohio tripped out, Harding–Chamberlain (3:05 P.M.), Hanna–Juniper (3:32 P.M.), and Start–South Canton (3:41 P.M.). They were all tripped out due to tree faults caused by overgrown vegetation. With these three 345-kV line out, power flowed

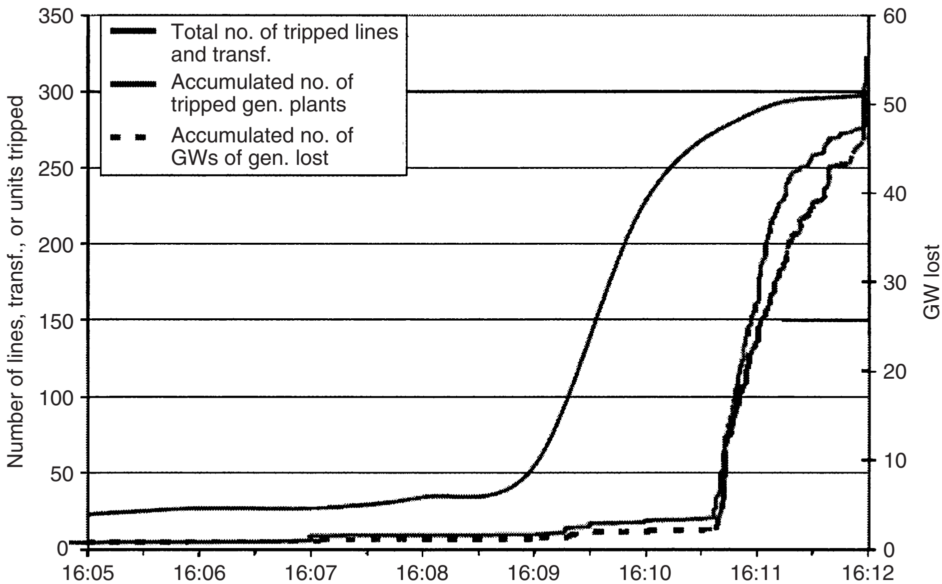

FIGURE 23-40 Accumulated line and generator trips during the cascade [23].

over through other remaining lines including the underlying 138-kV system. This redirection of flow caused severe overloading in 138-kV lines. As a result between 3:39 P.M. and 3:58 P.M., seven 138-kV lines tripped. At 3:59 P.M., West Akron bus tripped due to breaker failure. This event caused another five 138 kV-lines to trip. A few minutes later, between 4:00 P.M. and 4:08 P.M., another four 138-kV lines tripped. Losses of these transmission lines disconnected northern Ohio from Eastern Ohio. The last 345-kV line between Sammis and Star tripped at 4:06 P.M. The loss of this line left northern Ohio without any 345-kV path to eastern Ohio, and initiated a cascading blackout across the northeast U.S. and Canada. Within 7 min after the loss of 345-kV Sammis–Start line, more than 508 generating units at 265 power plants had been lost, and close to 300 lines and transformers tripped.

23.6.9 Power Quality Characteristics in the Great Northeastern Power Blackout of 2003

A major power quality characteristic of the blackout was sagging voltage when transmission lines experienced fault clearing operations (opening and reclosing) due to tree contacts.

An 8-cycle voltage sag was measured at an industrial site in Cleveland at about 3:45 P.M. This was when a series of 138-kV lines experience tree faults and attempted to isolate them (Fig. 23-41). This particular fault was detected and cleared promptly, but the voltage recovery at the site appears to be slow, suggesting that the system was now much weaker than previously. At least one more line was out of service.

Shortly after 4:00 P.M. there was another instantaneous voltage sag recorded (Fig. 23-42). The voltage drops abruptly and remains at the lower level. Phase unbalance develops, suggesting either the presence of a remote fault or that the system has become very weak due to the tripping of another line.

A short time later (accuracy of the time stamp is uncertain), the disturbance in the voltage shown in Fig. 23-43 was recorded in an office building in downtown Manhattan. This waveform is consistent with that of a power system that is going unstable.

Waveforms of this type can be observed in system dynamics simulations for buses in the weaker part of the system as it begins to move relative to a more distant part of the system that remains in

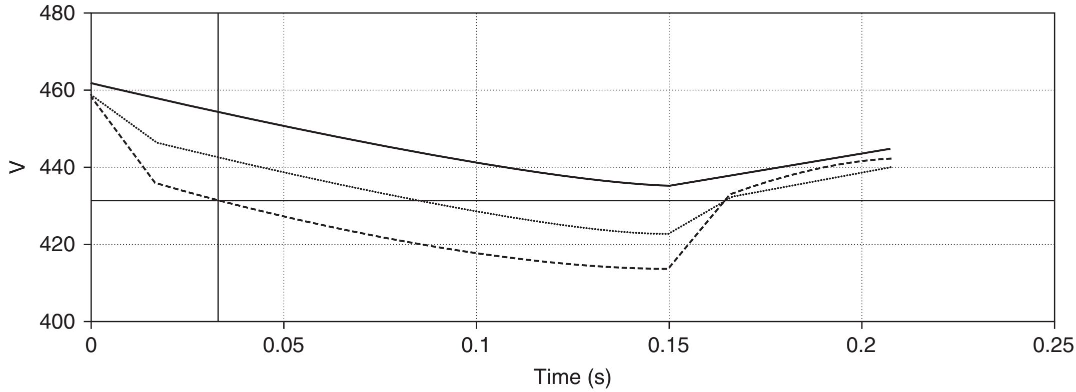

FIGURE 23-41 Instantaneous sag on phase C captured at service entrance of Cleveland industrial facility at around 3:45 P.M. (note time stamp is off by about 12 min) likely due to a fault on a transmission line. Voltage recovers slowly after fault is cleared, suggesting a weakened system. (*Courtesy of Electrotek Concepts and Dranetz-BMI*.)

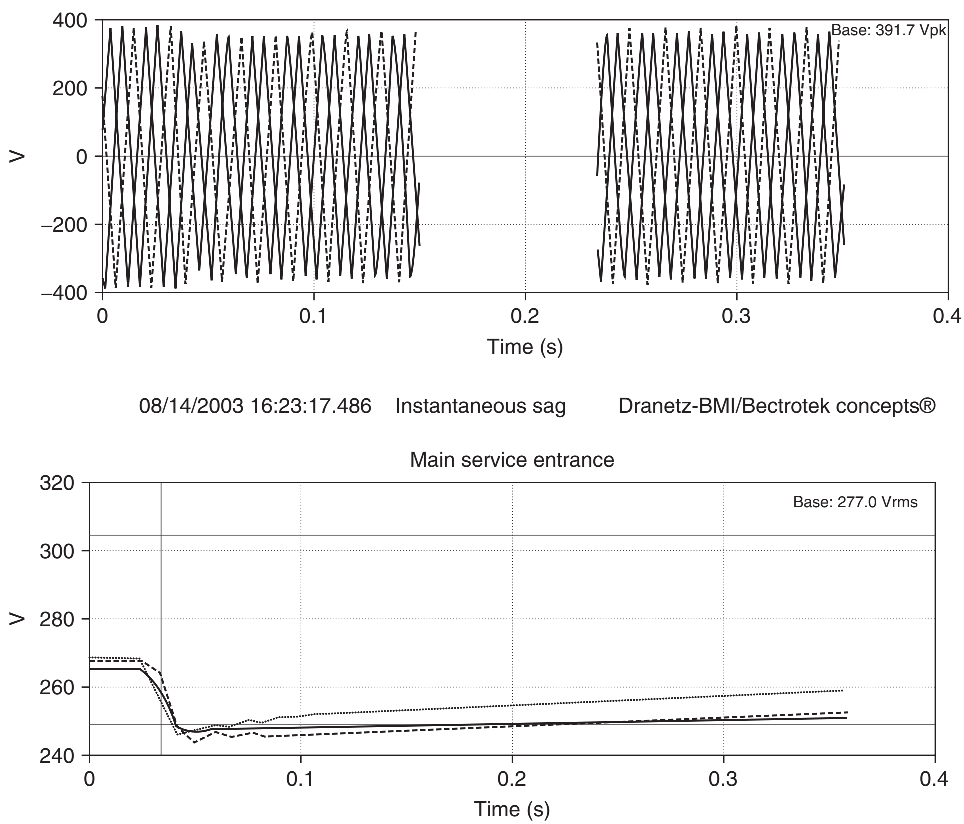

FIGURE 23-42 3-Phase instantaneous sag shortly after 4 P.M. on August 14. (*Courtesy of Electrotek Concepts and Dranetz-BMI*.)

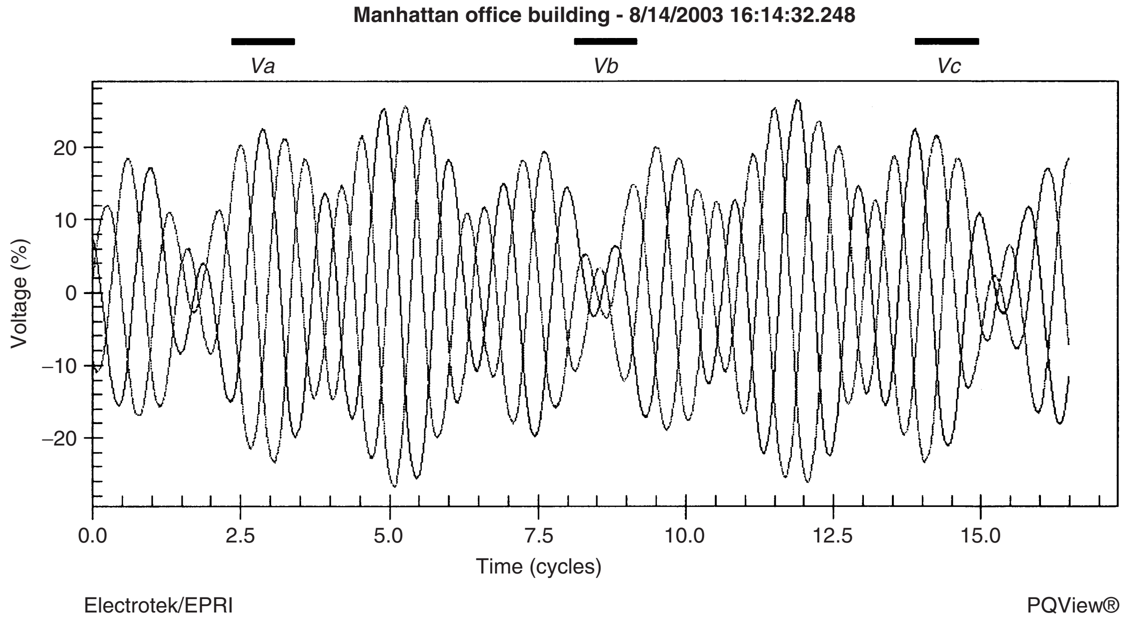

FIGURE 23-43 Waveform captured as the grid collapsed in New York City showing the instability of the system. (*Courtesy of Electrotek Concepts and Dranetz-BMI.*)

synchronism. A "beating" frequency develops as the two interconnected systems operate at different frequencies. In this case, it would appear that the system containing this power monitor had drifted by approximately 2 Hz from the rest of the system. Once this occurred, the power system supplying Manhattan detected the instability and immediately shut down the generators and separated from surrounding power systems.

Several of the neighboring systems successfully separated and remained stable throughout the blackout period despite briefly experiencing voltage waveforms like this while they were still interconnected with the part of the system that was collapsing.

Once the massive amount of load in the affected areas was lost, the entire eastern interconnection experienced a jump in frequency of approximately 0.2 Hz. This could be seen over a large geographic area (Fig. 23-44). After a few minutes, generator controls brought the average frequency back to 60 Hz and few energy users outside the affected area realized that anything had happened. While large in terms of system dynamics issues, this frequency change is inconsequential to most loads.

Figure 23-45 shows the complete rms voltage trend for the Manhattan site from the beginning of the blackout shortly after 4:00 P.M. on August 14 until the power was restored at 5:30 A.M. on August 15.

REFERENCES

1. TC77WG6 (Secretary) 110-R5, Draft Classification of Electromagnetic Environments, January 1991.
2. IEEE Std 1159-1995, Recommended Practice on Monitoring Electric Power.
3. IEC 50 (161) (1989), International Electrotechnical Vocabulary, Chapter 161: Electromagnetic Compatibility.
4. UIE-DWG-3-92-G, "Guide to Quality of Electrical Supply for Industrial Installations," Part 1: General Introduction to Electromagnetic Compatibility (EMC), Types of Disturbances and Relevant Standards. Advance UIE Edition. "Disturbances" Working Group GT 2.

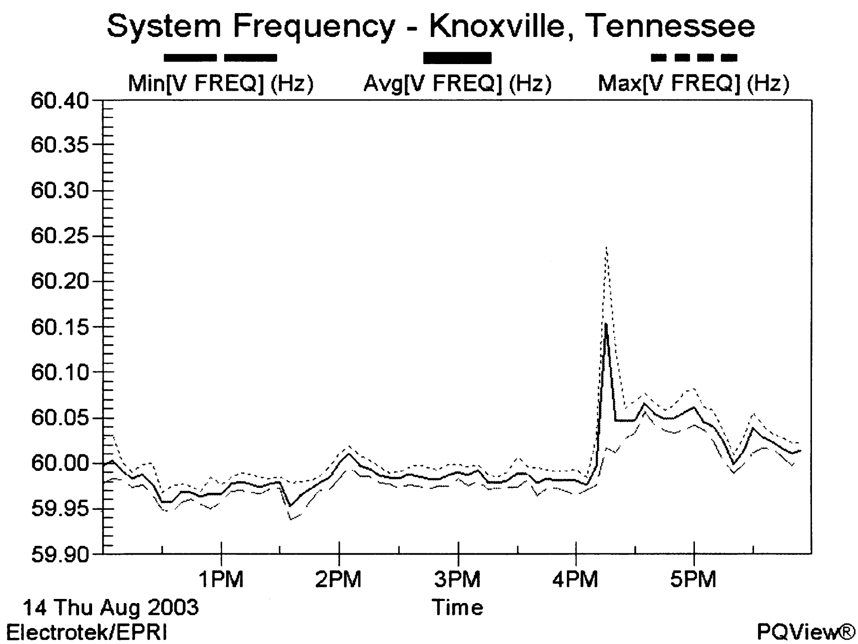

FIGURE 23-44 System frequency jump when the major systems separated was seen in locations as far away as Knoxville, TN. (*Courtesy of Electrotek Concepts and Dranetz-BMI.*)

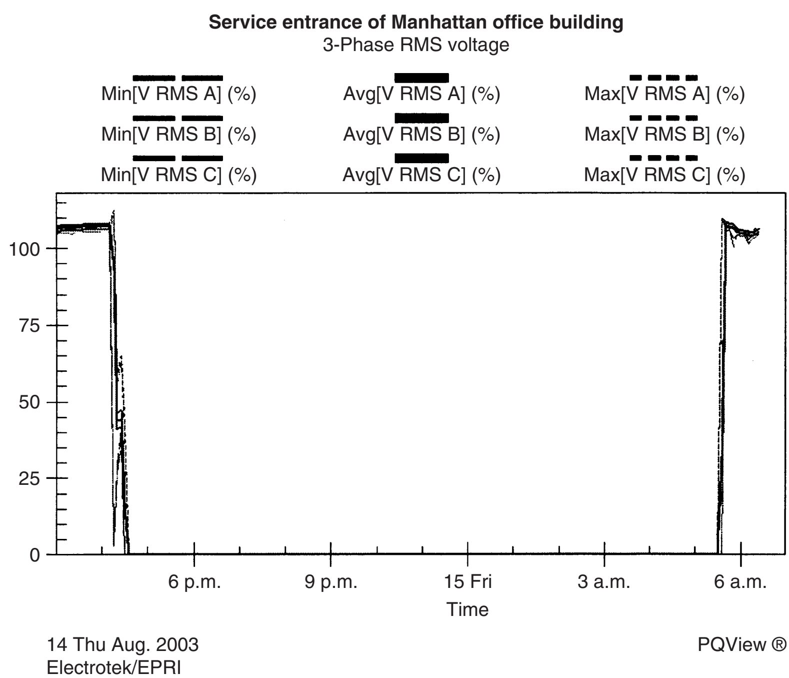

FIGURE 23-45 Rms voltage trend showing the min/max/avg of all three phases for the entire duration of the blackout at a Manhattan office building. (*Courtesy of Electrotek Concepts and Dranetz-BMI.*)

5. UIE-DWG-2-92-D, UIE Guide to Measurements of Voltage Dips and Short Interruptions Occurring in Industrial Installations.
6. IEC 61000-2-1(1990-05), "Description of the environment—Electromagnetic environment for low frequency conducted disturbances and signaling in public power supply systems," Electromagnetic Compatibility (EMC)—Part 2 Environment, Section 1, 1990.
7. ANSI/NFPA 70-1993, National Electrical Code.
8. IEEE Std 100-1992, IEEE Standard Dictionary of Electrical and Electronic Terms.
9. IEEE Std 446-1987, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications (IEEE Orange Book).
10. Information Technology Industry Council (ITI), 1250 Eye Street NW, Suite 200, Washington, DC, http://www.itic.org
11. IEC 61000-4-30 77A/356/CDV, Power Quality Measurement Methods.
12. IEC 61000-4-15, Flicker Meter—Functional and Design Specifications.
13. J. Lamoree, D. Mueller, P. Vinett, W. Jones, "Voltage Sag Analysis Case Studies," 1993 IEEE I&CPS Conference, St. Petersburg, FL.
14. R. C. Dugan, L. A. Ray, D. D. Sabin, et al., "Impact of Fast Tripping of Utility Breakers on Industrial Load Interruptions," Conference Record of the 1994 IEEE/IAS Annual Meeting, Vol III, Denver, October 1994, pp. 2326–2333.
15. IEEE Transformers Committee, "Secondary (Low-Side) Surges in Distribution Transformers," *Proceedings of the 1991 IEEE PES Transmission and Distribution Conference*, Dallas, September 1991, pp. 998–1008.
16. G. L. Goedde, R. C. Dugan, L. D. Rowe, "Full Scale Lightning Surge Tests of Distribution Transformers and Secondary Systems," *Proceedings of the 1991 IEEE PES Transmission and Distribution Conference,* Dallas, September, 1991, pp. 691–97.
17. Consortium for Electric Reliability Technology Solutions, "Review of Recent Reliability Issues and System Events," Grid of the Future White Paper, December, 1999.
18. Web site http://blackout.gmu.edu, accessed on February 24, 2005.
19. U.S. Department of Energy, The Con Edison Power Failure of July 13 and 14, 1977, Final Report, June 1978.
20. TIME, "Nigh of Terror," July 25, 1977, pp. 12–26.
21. Lesson Learned From the 1977 Blackout Case Study 1—Sequence of Events, www.blackout.gmu.edu/archive/pdf/lessons_learned_77.pdf, accessed on February 24, 2005.
22. North American Electric Reliability Council, Technical Analysis of the August 14, 2003, Blackout: What Happened, Why, and What Did We Learn, July 13, 2004.
23. U.S.–Canada Power System Outage Task Force, Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendation, April 2004.