Transmission Power Quality Benchmarking Methodology

Technical Report

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REPORT SUMMARY

In 1990, EPRI initiated a power quality monitoring project at the distribution level known as the EPRI DPQ Project. During this project, twenty-four utilities monitored power quality levels on their distributions circuits. Nearly 300 sites were monitored for a period of approximately two years. The data gathered were characterized and analyzed to form a baseline of power quality on U.S. distribution circuits.

Background
As interest in the results of the DPQ Project grew, utilities around the world began to participate in national and individual studies to benchmark power quality at the distribution level. However, considerably less effort has been directed at benchmarking power quality at the transmission level. Several reasons among many for this situation include the relative proximity to the end user, the additional costs of monitoring at the transmission level, and the fact that transmission-level events are indirectly included in distribution assessments. The practice of serving large, influential customers from transmission systems continues to grow, and the traditional vertically integrated utility is unbundling into three companies: generation, transmission, and distribution. Utilities, therefore, have become aware of the need to benchmark the power quality performance of the transmission system separately from the performance of the distribution system.

Objective
To determine what power quality phenomena play a role in transmission-level power quality, reliability, and performance; to determine the effectiveness of several methods used to benchmark power quality (for example, short-circuit analysis, monitoring—both direct and indirect—and state estimation); and, to determine the process for selecting a statistically valid sample from a large group of transmission lines and systems.

Approach
The investigation team used a straightforward approach to accomplish the objectives of the TPQ Project. Team members used document review, simulations, and their own practical experiences. They researched and analyzed each method to determine its limitations and feasibility of implementation. When required, members performed simulations to verify their hypotheses.

Results
Following are some of the relevant results presented in this report:

- Using short-circuit analysis software is a viable alternative to performing actual monitoring on the transmission system. A more accurate picture of voltage variations can be presented if the simulation software provides a means to incorporate utility fault-clearing schemes and available historical data on system performance.

- Actual monitoring of the transmission system provides greater accuracy over short-circuit analysis techniques. Monitoring on the transmission level is preferred for benchmarking the transmission system, but simulations have shown that algorithms can be developed that allow use of less costly distribution-system monitors for benchmarking the transmission system.
- By using state estimation, utilities can incorporate limited transmission-level monitoring with short-circuit simulations to produce accurate results for the entire transmission system. Transmission-level state estimation software is still in the embryonic stage, but project results indicate this type of system will be commercially available within the next few years.

EPRI Perspective

For years, EPRI has been involved in helping utilities improve their level of customer service. With deregulation of vertically integrated utilities well underway, EPRI is even more dedicated to helping their member utilities provide the best, most reliable service to their customers. Having detailed knowledge of the transmission system will greatly increase a utility's ability to respond to customer needs. Benchmarking power quality and performance of the transmission system is just one step that a utility can take towards adding more value to products they offer. The ability to provide performance and power quality information on the utility's transmission system will help customers make educated decisions concerning selecting and procuring mitigation equipment, which, in the end, will greatly increase their efficiency and success.

Keywords

Transmission power quality
Transmission monitoring
Transmission benchmarking

ABSTRACT

The purpose of the Transmission Power Quality Benchmarking Methodology Project is to evaluate the various techniques for benchmarking power quality levels on transmission systems. In this report, the various types of power quality events that affect transmission systems and transmission-fed customers are identified. Analysis techniques are described for each type of relevant power quality event. Three benchmarking methodologies are identified: short-circuit analysis, monitoring, and state estimation. Each technique was researched and evaluated based on engineering and economic principals. All three methodologies have merit and are worth considering when performing a power quality benchmarking project at the transmission level.

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
INTRODUCTION

In 1990, EPRI embarked on a project to monitor the power quality at a sample of distribution sites. Commonly known as the EPRI DPQ Project (EPRI RP-3098), the project measured the power quality on some 300 sites across the United States for approximately 2 years. This project culminated in a three-volume report (TR-106294V1, V2, and V3) that was published in 1996 [1].

With the wealth of knowledge and information gained from the DPQ Project about distribution-level power quality, EPRI decided to evaluate the need for and feasibility of a similar type of study at the transmission level. The Transmission Power Quality (TPQ) Project is intended to address several issues on monitoring transmission power quality:

- **Problem solving**. Special-purpose monitoring to understand phenomena associated with specific events or conditions on the system, such as capacitor switching, line switching, and staged tests.
- **Benchmarking**. Monitoring on the transmission system to characterize its overall power quality performance. Guidelines must include issues such as site selection, monitor requirements, and data analysis.
- **Predictive maintenance and automatic evaluation of events**. This type of monitoring may require special evaluation algorithms and monitoring at every location where this type of monitoring is desired. This may be the most important type of power quality monitoring in the future.

The TPQ Project will evaluate methodologies of monitoring, simulating, and estimating power quality levels on transmission systems. Three methods of determining the power quality levels on transmission systems are evaluated in this report:

- **Estimation**. Using a short-circuit analysis program, voltage-sag performance of the transmission system is estimated. Historical data from utilities is used in conjunction with system configurations.
- **Measurement**. Actual measurement of power quality phenomena on transmission systems. Two approaches are addressed: direct measurement of transmission-level voltages and currents and distribution-level monitoring of power quality events while filtering out distribution events.
- **Hybrid approach**. By using state estimation and limited monitoring, an approach is developed that estimates the power quality levels on the transmission system.

This report describes the preferred methodology for implementing a project to benchmark the power quality of a transmission system. The scope of this report is focused toward AC aboveground transmission lines. While many of the issues discussed also apply to cable-transmission or DC systems; however, those systems have additional considerations that are not specifically addressed in this report.

This report addresses the type of data that should be collected, as well as where and how it should be collected. The different equipment options for collecting this data are discussed along with the specific requirements for both the data-collection and data-analysis systems. The report describes three different methods for benchmarking a system and a methodology for incorporating a transmission-system state estimator to expand the coverage of the monitoring effort.

Report Organization

The objective of this report is to provide an overview of the various methodologies and techniques that can be used to perform transmission-level power quality monitoring and benchmarking. Three methodologies are discussed in detail. The pros and cons of each method are given, as well as a comparison between each method.

Chapter 2 of this report describes the types of power quality phenomena of interest to utilities for transmission systems and why they are an important part of any transmission-level benchmarking project.

Chapter 3 of this report discusses techniques used for analyzing the power quality data of interest as described in Chapter 2. Example analysis techniques are given for RMS variations, transients, harmonics, steady-state quantities, and special cases like flicker.

Chapter 4 of this report discusses the issues that surround site selection. When performing a benchmarking project, selection of the monitoring points is crucial. This chapter discusses the various power quality events and the appropriate methods used to select sites for a benchmarking project.

Chapter 5 of this report addresses the statistical method used to assist engineers in designing a large-scale monitoring project. When performing monitoring projects that make inferences about a population based on a sample of that data, the sample must be similar to the target population in all relevant aspects, and certain aspects of the measured variables must conform to the assumptions that underlie the statistical procedures.

Chapter 6 discusses using software for short-circuit analysis to benchmark a transmission system. It identifies the data that needs to be collected and the limitations of this approach.

Chapter 7 of this report addresses the issues associated with monitoring power quality levels on transmission systems. Two approaches are identified for monitoring power quality levels on transmission systems: direct monitoring of the transmission system and indirect monitoring of the power quality levels on the transmission system via distribution-level monitors. The pros and cons of each method are discussed, as well as system information and characteristics that are required to ensure a successful monitoring project.

Chapter 8 of this report describes the techniques and methodologies used when performing power quality benchmarking using a hybrid approach such as state estimation. By using state-estimation techniques, a utility can perform benchmarking on a transmission system with a limited number of power quality monitors. This is accomplished through the use of strategically placed power quality monitors and state estimation techniques.

Chapter 9 of this report compares the three methodologies described in chapters 6 through 8. The pros and cons of each methodology are given, and comparisons between each methodology are illustrated.

Chapter 10 presents conclusions about the “best” approach for performing a transmission-level power quality monitoring project.

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2
RECOMMENDED DATA-COLLECTION METHOD FOR BENCHMARKING

The purpose of benchmarking is to characterize the overall system performance. A characterization of a system should enable meaningful comparisons with other transmission systems and industry standards, as well as enable the trending of the characteristics over time. A characterization needs to be transportable on a global scale so that the performance of transmission systems all over the world can be compared.

Selecting the measured values that will be the foundation for a characterization requires keeping an eye on the future. Whenever possible, the quantities measured should remain flexible to allow for changes in industry standards or designs. Finally, the measured quantities selected for inclusion in a benchmarking project need to be readily available and economically collectable on a global basis.

The measured quantities that have been selected for benchmarking transmission power quality can be grouped into the following 7 categories: RMS voltage variations, transmission line interruptions, voltage transients, voltage phase unbalance, system frequency variations, voltage fluctuations (flicker), and waveform distortion.

RMS Voltage Variations

RMS voltage variations are an important benchmark characterization for a transmission system because they are indicative of the overall health of the transmission system. An increase in the number or severity of events may indicate that certain maintenance issues need to be addressed, while absolute values outside of industry averages may suggest that some fundamental design issues need to be re-evaluated.

RMS voltage variations are excursions of the voltage outside the tolerances required to maintain the customer utilization voltage within the limits specified in ANSI Standard C84.1 for periods greater than ½ cycle. RMS variations are classified as short-duration or long-duration, depending on whether the excursion lasts beyond one minute. All references to “RMS variations” are to be interpreted to mean “true RMS variations,” as opposed to the RMS value of the fundamental component alone [1].

Short-Duration RMS Voltage Variations (Sags, Swells, and Interruptions)

Short-duration variations are further classified as instantaneous (½ to 30 cycles), momentary (30 cycles to 3 seconds), and temporary (3 seconds to 1 minute). Short-duration decreases in RMS voltage, called *sags*, are most frequently caused by faults. The IEC term for this phenomenon is *dip*. The two terms are considered interchangeable, with *sag* being preferred by the United States power quality community. Because most faults are successfully removed very quickly, most voltage sags resulting from transmission-line faults are of the instantaneous type. Any decrease in RMS voltage between 0.9 per unit and 0.1 per unit that lasts between 0.5 cycles and 1 minute is considered a *sag* [2].

Single line-to-ground faults are the dominant cause of *swells*—short-duration increases in RMS voltage. Until the fault is cleared, the unfaulted phases will be subjected to a swell whose magnitude depends on the system grounding ratio (Z0/Z1). The swell can be as high as 1.73 per unit for an ungrounded system. Any increase in RMS voltage above 1.1 per unit that lasts between 0.5 cycles and 1 minute is considered a *swell*. Typical values are between 1.1 and 1.8 per unit.

Interruptions are a decrease in voltage to less than 0.1 per unit for less than 1.0 minute. It would be very rare for a fault on the transmission system to cause an interruption to a customer because of the interconnected nature of the transmission system.

Long-Duration RMS Voltage Variations (Undervoltage, Overvoltage, and Outages)

Once an RMS voltage variation exceeds 1 minute in duration then it is classified as a long duration event. An *undervoltage* is a sag that lasts longer than 1 minute, an *overvoltage* is a swell that lasts longer than 1 minute and an *outage* is an interruption that lasts longer than 1 minute.

Transmission-Line Interruptions

Retaining the details about unscheduled operations of transmission-line breakers creates a very useful database for understanding and tracking the performance of a transmission system. Interruption statistics are indicative of the overall health of the transmission system in much the same way that RMS voltage variations are. However, such statistics are more of an overall indicator because they include not only those events that are affiliated with faults but also any event that results in unscheduled breaker operation. Events such as relay misoperations or trips due to line overloads would be captured with these statistics but would probably not be captured with statistics on RMS voltage variations.

Interruption statistics affiliated with faults, in conjunction with the electrical model of the transmission system, can be used to estimate profiles on RMS voltage variations at any point within the electrical model. This capability is particularly useful because it is generally impractical to have monitors located at every node in the system. The accuracy of the RMS voltage profile increases with increased detail associated with the unscheduled breaker operation and the availability of any supplemental power quality monitoring data.

Voltage Transients

The number and severity of voltage transients are useful indicators because they give insight into the level of stress to which connected equipment could be exposed. Insulation damage caused by excessive voltage transients tends to be cumulative in nature. Trending and analyzing this benchmark can identify design and/or operational issues that may be detrimental to equipment longevity.

The term *transients* has been used in the analysis of power system variations for a long time. Its name immediately conjures up the notion of an event that is undesirable but momentary in nature. The IEEE Std 100-1992 definition of *transients* reflects this understanding. The primary definition uses the word *rapid* and talks about frequencies up to 3 MHz when defining transients in the context of evaluating cable systems in substations. The notion of a damped oscillatory transient due to an RLC network is also mentioned. This is the type of phenomenon that most power engineers think of when they hear the word transient [2].

Broadly speaking, transients can be classified into two categories: impulsive and oscillatory. These terms reflect the waveform of a current or voltage transient. However, it is the voltage transient that is being emphasized in this section.

Impulsive Transient

An impulsive transient is a sudden, non-power-frequency change in the steady-state condition of voltage, current, or both, that is unidirectional in polarity (primarily either positive or negative). Impulsive transients are normally characterized by their rise and decay times. These phenomena can also be described by their spectral content. For example, a 1.2/50-µs, 2000-V impulsive transient rises 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 transients is lightning. Figure 2-1 illustrates a typical impulsive current transient caused by lightning [2].

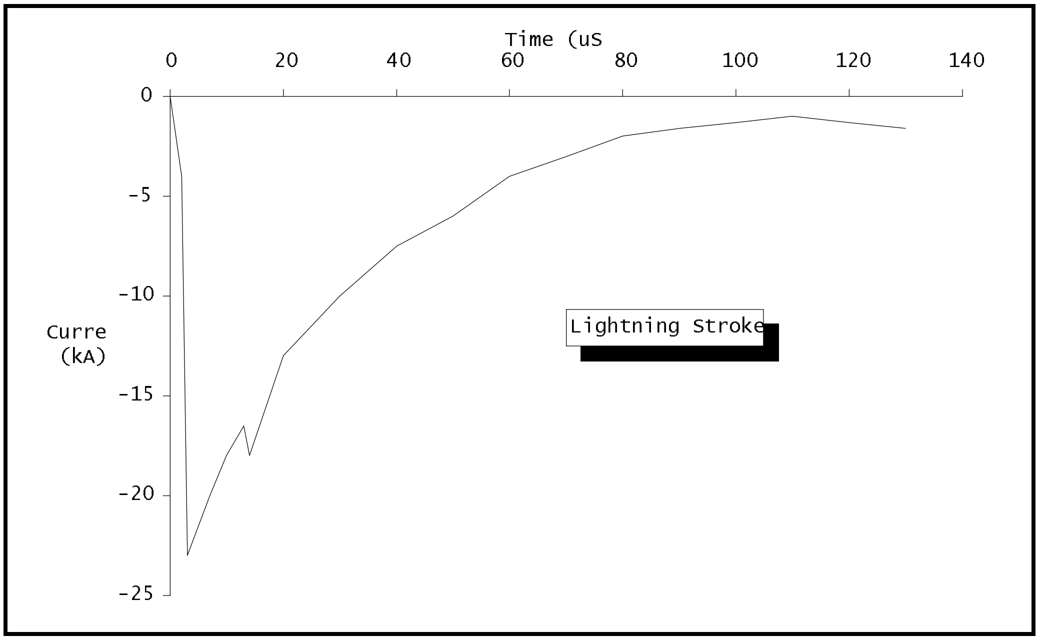

Figure 2-1
Impulsive Transient on the Power System Caused by a Lightning Stroke

Due to the high frequencies involved, impulsive transients are damped quickly by resistive circuit components and are not conducted far from their source. There can be significant differences in the transient characteristic from one location to another. Impulsive transients can excite power-system resonance circuits and produce oscillatory transients.

Oscillatory Transient

An oscillatory transient is a sudden, non-power-frequency change in the steady-state condition of voltage, current, or both, that includes both positive and negative polarity values. An oscillatory transient consists of a voltage or current whose instantaneous value changes polarity rapidly. It is described by its spectral content (predominant frequency), duration, and magnitude. The subclasses of spectral content are high, medium, and low frequency. The frequency ranges for these classifications were chosen to coincide with common types of power-system oscillatory transients.

As with impulsive transients, oscillatory transients can be measured with or without the fundamental frequency component included. When characterizing the transient, it is important to indicate the magnitude with and without the fundamental component. High-frequency oscillatory transients have a primary frequency component greater than 500 kHz and a typical duration measured in microseconds (or several cycles of the predominant frequency). These transients are almost always due to some type of switching event. High-frequency oscillatory transients can also be the result of a local system response to an impulsive transient.

Medium-frequency transient have a primary frequency component between 5 kHz and 500 kHz and a duration measured in the tens of microseconds (or several cycles of the principal frequency). Back-to-back capacitor energization results in oscillatory transient currents in the tens of kilohertz. This phenomenon occurs when a capacitor bank is energized in close electrical proximity to a capacitor bank already in service. The energized bank sees the de-energized bank as a low-impedance path (limited only by the inductance of the bus to which the banks are connected, typically small). Figure 2-2 illustrates the resulting current transient due to back-to-back capacitor switching. Cable switching results in oscillatory voltage transients in the same frequency range as back-to-back capacitor switching. Medium-frequency transients can also be the result of a system response to an impulsive transient [2].

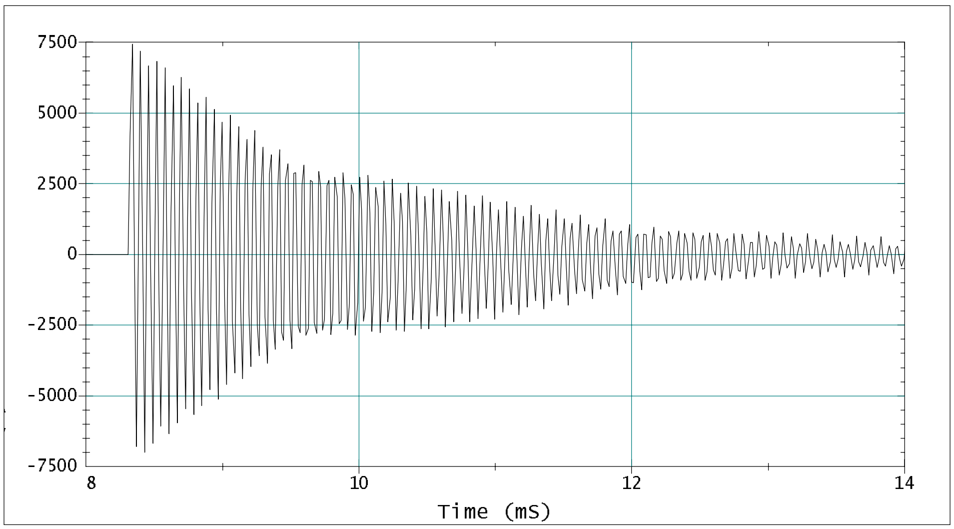

Figure 2-2
Oscillatory Transient Caused by Back-to-Back Capacitor Switching

Low-frequency transient have a primary frequency component less than 5 kHz, and a duration from 0.3 ms to 50 ms. This category of phenomenon is frequently encountered on sub-transmission and distribution systems and is caused by many types of events, primarily the energization of capacitor banks. The resulting voltage waveform is very familiar to power system engineers and can be readily classified using the attributes discussed so far. Capacitor-bank energization typically results in an oscillatory voltage transient with a primary frequency between 300 and 900 Hz. The transient has a peak magnitude that can approach 2.0 pu, but is typically 1.3 to 1.5 pu lasting between 0.5 and 3 cycles, depending on the system damping (see Figure 2-3) [2].

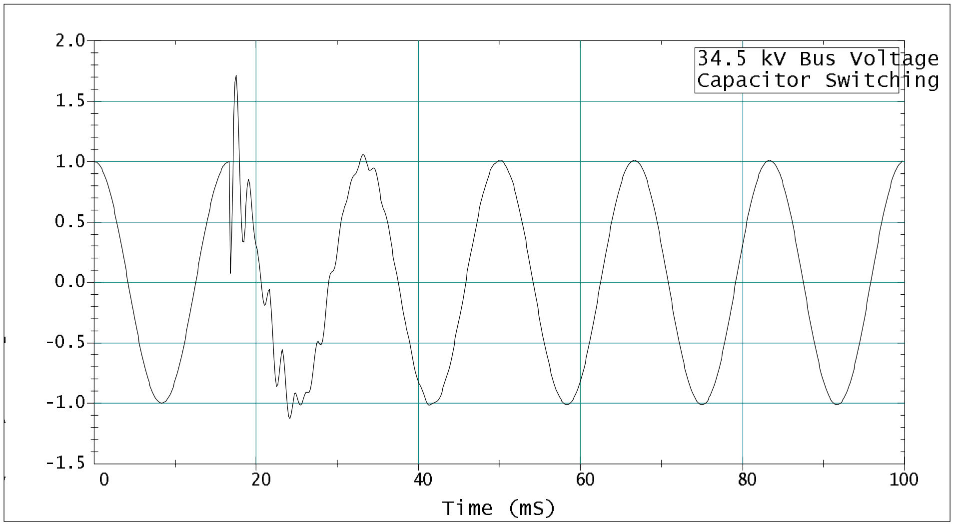

Figure 2-3
Low-Frequency Oscillatory Transient Caused by Capacitor-Bank Energization

Voltage Phase Unbalance

Excessive voltage phase unbalance (percent unbalance > 1 or 2%) should be monitored and used as a benchmark because it can cause excessive heating in connected equipment. Early detection and correction of phase unbalance problems can preserve equipment lifespan.

Voltage unbalance can be defined in terms of negative-sequence unbalance, zero-sequence unbalance, or percent unbalance of phase voltages. Negative-sequence unbalance is defined as V_2 / V_1, while zero-sequence unbalance is defined as V_0 / V_1. Percent unbalance of phase voltages is defined as the ratio of the maximum deviation of a phase voltage from the average of the total phases to the average of the phase voltages, expressed in percent [2].

Percent Unbalance = Abs((MaxDev RMS - Average RMS) / Average RMS) * 100%

Where MaxDev is either the maximum or minimum of the three voltage magnitudes.

System Frequency Variations

System frequency variations tend to be rather small, with typical values ranging between 0.01 Hz and 0.05 Hz. An accumulation of frequency snapshots over time gives a general indication of the “stiffness” of the system. This benchmark may prove particularly beneficial as more and more distributed generators are added to the electrical grid.

The frequency of the power system is directly related to the rotational speed of the generators on the system. At any instant, the frequency depends on the balance between the load and the capacity of the available generation. When this dynamic balance changes, small changes in frequency occur. The size of the frequency shift and its duration depend on the load characteristics and the response of the generation system to load changes [2].

Dynamic frequency variations that go outside of accepted limits for normal steady-state operation of the power system are normally caused by faults on the bulk power transmission system, a large block of load being disconnected, or a large source of generation going off-line. Oscillations on the order of 0.05 Hz have been known to exist just prior to system instability.

Voltage Fluctuations (Flicker)

International standards have recently been developed that allow the quantification of voltage flicker. These standards suggest specific planning limits for transmission systems, which makes voltage flicker a useful benchmark to monitor.

Flicker, or voltage fluctuation, refers to the phenomenon of observable light flicker, normally associated with an incandescent bulb. Loads that exhibit continuous, rapid variations in the load current, particularly the reactive component, can cause voltage variations often referred to as flicker. The fluctuation is caused by modulation of the fundamental frequency voltage by a signal whose frequency is typically less than 25 Hz. Modulating signal magnitudes as low as 0.5% of the fundamental can result in perceptible lighting flicker for frequencies between 1-5 Hz.

From the point of view of a utility application, voltage fluctuations have usually been of interest, perhaps because voltage changes are easily measured with existing instrumentation. Historically, these voltage changes have been used in conjunction with “flicker curves,” such as those shown in Figure 2-4. These curves, derived from controlled experiments, offer thresholds of perception and/or irritability when periodic rectangular voltage fluctuations occur continuously (only threshold of irritability curves are shown) [3].

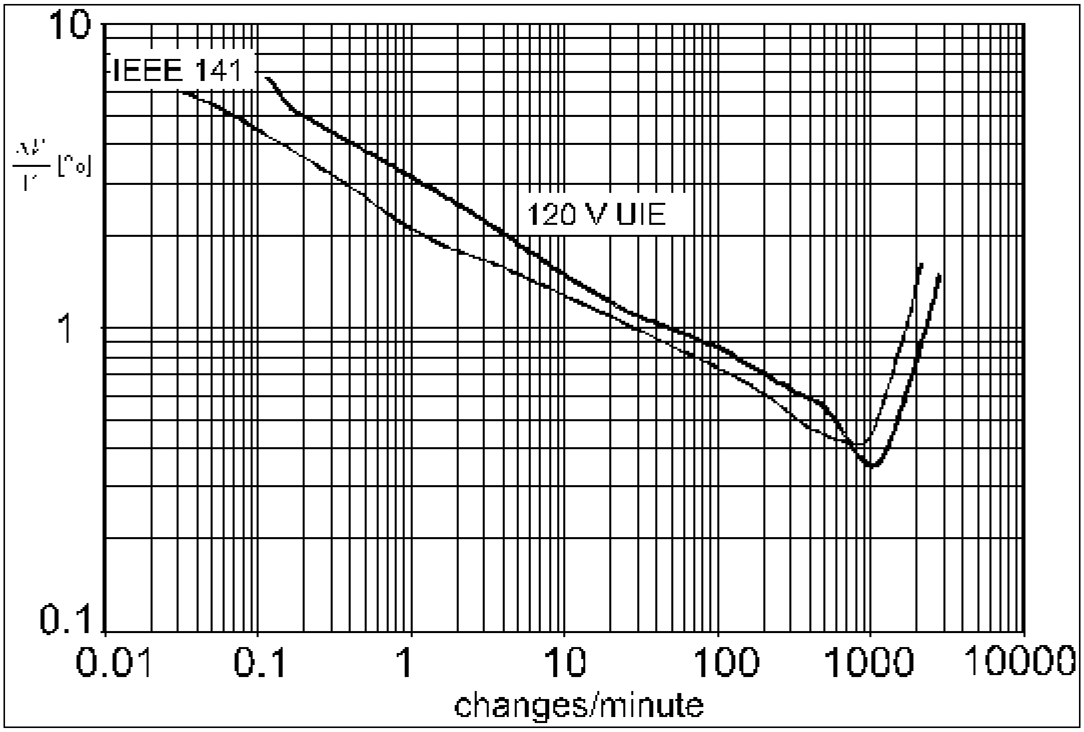

Figure 2-4
Historical Flicker Curve (Percent Voltage Change versus Modulation Frequency)

The historical flicker curves are limited because they do not address many of the variables such as modulation type (sinusoidal or rectangular), bulb characteristics (type, watt, and voltage rating), or the summation of "flicker dosages" if there is more than one source of flicker. A relatively new international standard (IEC 61000-4-15) addresses these limitations.

The IEC standard defines a flicker meter (adjustable transfer function), which translates a measured voltage signal into two statistical indices (P_{st} and P_{lt}). The short-term flicker severity index, P_{st}, is a statistical quantification of the instantaneous flicker sensation and is derived from a time-at-level analysis of the instantaneous flicker sensation. A single P_{st} value is calculated every 10 minutes. P_{st}>1 corresponds to the level of irritability for 50% of the persons subjected to the measured flicker. The long-term flicker severity index, P_{lt}, is a combination of 12 P_{st} values. Practical flicker limits are typically developed from 95th and 99th percentiles of a series of P_{st} and P_{lt} values collected over time periods perhaps as long as one week.

Another IEC standard (IEC 61000-3-7) gives P_{st} and P_{lt} planning level limits for medium-voltage and high-voltage systems. As a general guideline, P_{st} and P_{lt} should not exceed the planning levels more than 1% of the time, with a minimum assessment period of 1 week. The Standard distinguishes between P_{st} and P_{lt} values measured throughout a supply system and those associated with a particular fluctuating load. Planning levels (usually denoted as L_{Pst} and L_{Plt}) apply throughout a supply system; the aggregate effects of all fluctuating loads must be taken into account. Emission limits for individual loads (denoted as E_{Pst} and E_{Plt}) must be set so that the combined effects do not exceed planning levels [3].

Waveform Distortion

Waveform distortion is defined as a steady-state deviation from an ideal sine wave of the power frequency, principally characterized by the spectral content of the deviation. Distortions in the sinusoidal voltage and/or current waveforms are potentially troublesome because they can cause equipment overheating and/or failure, fuse blowing, increased neutral currents, control misoperation, and communication interference. There are five primary types of waveform distortion:

1. Harmonics
2. Interharmonics
3. Notching
4. DC offset
5. Noise

Standards have been developed that quantify and set limits for many of these types of waveform distortion at the transmission level, which makes them useful benchmarks.

Harmonics

Harmonics are sinusoidal voltages or currents having frequencies that are integer multiples of the frequency at which the supply system is designed to operate (the fundamental frequency, usually 50 Hz or 60 Hz). Harmonics combine with the fundamental voltage or current and produce waveform distortion. Harmonic distortion exists due to the nonlinear characteristics of devices and loads on the power system. For example, Figure 2-5 shows the waveform and harmonic spectrum of an adjustable-speed drive (ASD) [2].

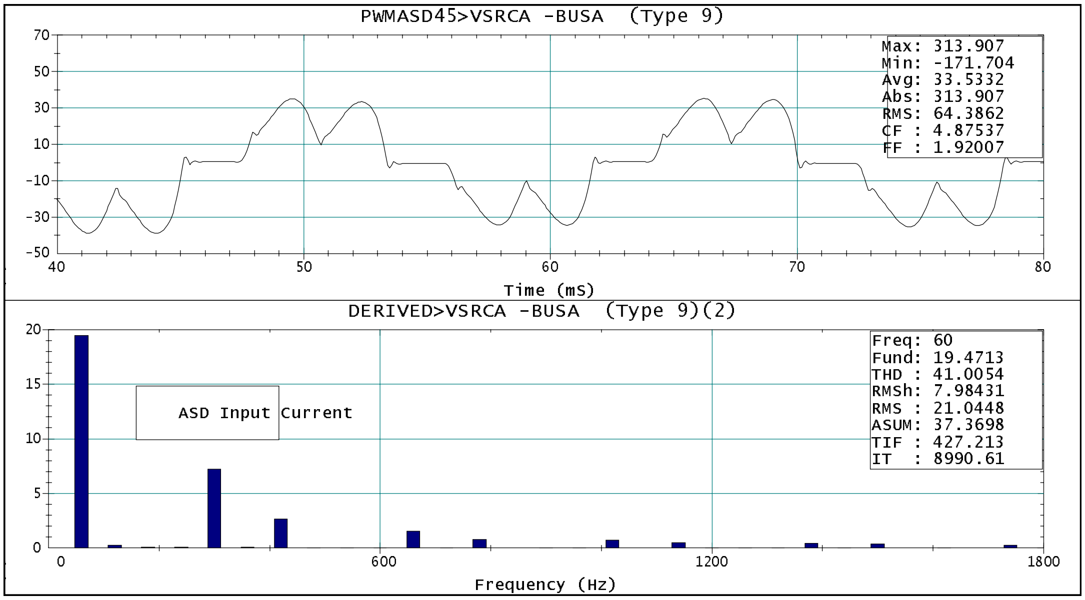

Figure 2-5
Input-Current Waveform and Harmonic Spectrum of an ASD

Devices that generate harmonics can usually be modeled as current sources that inject harmonic currents into the power system. Voltage distortion results as these currents cause nonlinear voltage drops across the system impedance. Harmonic distortion is a growing concern for many customers and for the overall power system due to increasing application of power electronics equipment.

Harmonic distortion levels can be characterized by the complete harmonic spectrum with magnitudes and phase angles of each individual harmonic component. It is also common to use a single quantity, the total harmonic distortion (THD), as a measure of the magnitude of harmonic distortion:

$$THD = \frac{1}{V_1}\sqrt{\sum_{h=2}^{h_{\max}} V_h^{\,2}} * 100\% \qquad \textbf{2-1}$$

Where V_h = RMS voltage magnitude at harmonic h, and h_{Max} = highest resolved harmonic

IEEE 519 has established suggested harmonic voltage limits for both THD and the single largest component of THD as a function of transmission system voltage. In general, the maximum suggested value for both quantities decreases as the voltage level increases. The suggested harmonic voltage limits for 161-kV transmission systems (THD = 1.5%, Max Individual = 1.0 %) are also applicable for all transmission voltages above 161 kV [4].

The basic philosophy behind IEEE 519 is that the utility is responsible for maintaining the harmonic voltage levels while the customers are responsible for limiting the magnitude of harmonic currents injected into the power system.

Current distortion levels that are characterized by THD can often be misleading. For instance, many ASDs will exhibit high THD values for the input current when they are operating at very light loads. This is not a significant concern because the magnitude of harmonic current is low, even though its relative distortion is high.

To handle this concern for characterizing harmonic currents in a consistent fashion, IEEE 519-1992 defines another term, the total demand distortion (TDD). This term is the same as the THD except that the distortion is expressed as a percent of maximum demand load current rather than as a percent of the fundamental current magnitude.

The IEEE standard sets limits for TDD and the individual components as a function of short-circuit ratio (utility short-circuit current at the point of common coupling divided by customer average maximum demand load current). Higher levels of harmonic-current generation are allowed on stronger systems (higher short-circuit ratios) because it is harder for the customer to impact the system voltage distortion.

Interharmonics

The usefulness of interharmonics as a benchmark is limited at this time because the various standards are just starting to provide guidance on how to quantify them and determine acceptable limits. Both the IEC and IEEE standards are expected to address these issues in the next revision. It is anticipated that once these standards are adopted, the interharmonic benchmark will be quite meaningful because interharmonics are becoming more prevalent as power electronic load levels increase on the power system.

Voltages or currents having frequency components that are not integer multiples of the frequency at which the supply system is designed to operate (typically 50 Hz or 60 Hz) are called interharmonics. They can appear as discrete frequencies or as a wide-band spectrum.

Interharmonics can be found in networks of all voltage classes. The main sources of interharmonic waveform distortion are static frequency converters, cyclo-converters, induction motors, and arcing devices. Power-line carrier signals can also be considered interharmonics.

Interharmonic frequency components greater than the power frequency can cause heating in the same fashion as heating caused by harmonic currents. In addition to heating effects, a variety of system impacts have been reported. These effects include CRT flicker, torsional oscillations, overload of conventional series-tuned filters, overload of outlet strip filters, communications interference, ripple control (power-line carrier) interference, and CT saturation.

One of the more important effects of interharmonics is the impact on light flicker. Interharmonics are not synchronized with the fundamental and therefore affect the peak amplitude from one cycle to another. Differentiation between peak and RMS deviation impacts can be important because some loads are affected more by peak variations than RMS variations. For example, compact fluorescent lamps have been shown to be more sensitive to peak variations than RMS variations. Incandescent lamps, however, are more sensitive to RMS variations. It is interesting to note that the IEC standard flickermeter is sensitive to RMS variations as opposed to peak variations [5].

Notching

Notching is defined as a switching (or other) disturbance of the normal power voltage waveform, lasting less than 0.5 cycles, which is initially of opposite polarity than the waveform and is thus subtracted from the normal waveform in terms of the peak value of the disturbance voltage. This includes complete loss of voltage for up to 0.5 cycles [2]. Notching is normally a periodic voltage disturbance caused by the normal operation of power electronic devices when current is commutated from one phase to another. Because 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.

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 due to the effect of half-wave rectification. Life extenders for incandescent light bulbs, for example, may consist of diodes that reduce the RMS voltage supplied to the light bulb by half-wave rectification. Direct current in alternating current networks can have a detrimental effect by biasing transformer cores so that they saturate in normal operation. This causes additional heating and loss of transformer life. DC may also cause the electrolytic erosion of grounding electrodes and other connectors [6].

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. Basically, noise consists of any unwanted distortion of the power signal that cannot be classified as harmonic distortion or transients.

The frequency range and magnitude level of noise depend on the source that produces the noise and the system characteristics. A typical magnitude of noise is less than one percent of the voltage magnitude. Noise disturbs electronic devices such as microcomputers and programmable controllers. The problem can be mitigated by using filters, isolation transformers, and some line conditioners [6].

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3
DATA ANALYSIS

There have been many studies performed and reports and papers written on the topic of analyzing power quality. Most of these documents focused on analyzing power quality on distribution systems or within facilities. This chapter deals with analyzing power quality at the transmission level, which, in essence, is similar to analyzing power quality on the distribution system.

The categories for data analysis will be based on the Institute of Electrical and Electronics Engineers (IEEE) standard 1159-1995. The IEEE Std. 1159, *IEEE Recommended Practice for Monitoring Electric Power Quality*, was first published in 1995. Its purpose was to help instruct and educate engineers and other interested parties on the proper methods of monitoring and interpreting data for problems related to power quality [1].

Power Quality Categories

The IEEE Std. 1159-1995 breaks power quality events into seven major categories:

1. Transients
2. Short-duration variations
3. Long-duration variations
4. Voltage unbalance
5. Waveform distortion
6. Voltage fluctuations
7. Power-frequency variations

A brief description of each of these major categories follows. For more detailed information on any particular category or subcategory, the reader is referred to the IEEE Std. 1159-1995 itself.

Transients

Transients are caused by sudden changes in the electric power system. There are two main ways that energy can be suddenly injected into the power system:

1. Connection or disconnection of elements on the power system. Capacitor switching or line switching are examples of these types of events.

2. Injection of energy into the power system. A lightning strike or electrostatic discharge are examples of this type of event.

The IEEE Std. 1159-1995 divides transients into two subcategories: impulsive and oscillatory. Examples of each type of transient are given in Figure 3-1 and Figure 3-2. The major difference between the two types of transients is that the polarity of an impulsive transient in unidirectional, whereas the polarity of an oscillatory transient is bi-directional.

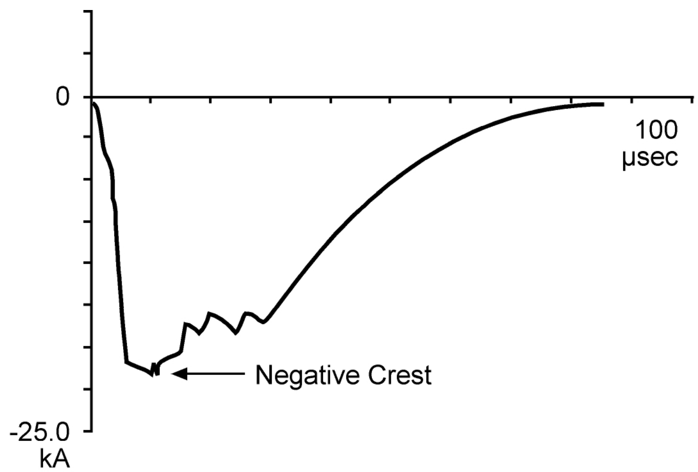

Figure 3-1
Example of an Impulsive Transient Caused by a Lightning Strike

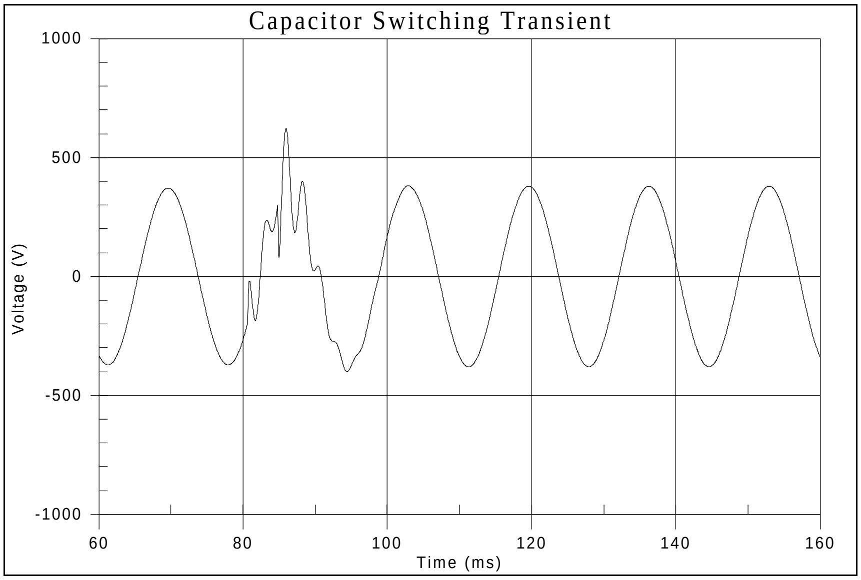

Figure 3-2
Example of a Typical Low-Frequency Oscillatory Transient Measured on a Power System

Typical causes of transients on the transmission system are line and equipment switching operations and lightning strikes.

Short-Duration Variations

Short-duration variations can be designated as instantaneous, momentary, or temporary, depending on their duration. All short-duration variations have durations of less than one minute. Short-duration variations—events such as voltage interruptions, sags, and swells that less than a minute—can be caused by:

1. A fault on the power system.

2. Loose wiring connections.

3. The energization or de-energization of large loads.

For transmission systems, a fault on the power system is the most prevalent cause for short-duration variations. Figure 3-3 illustrates a short-duration variation (within a facility).

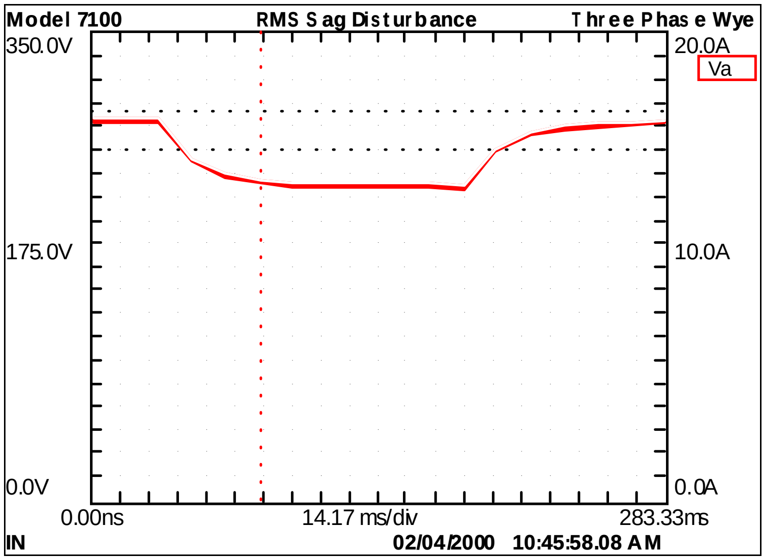

Figure 3-3
Example of a Short-Duration Variation (Instantaneous Sag)

Long-Duration Variations

Long-duration variations are variations at the power frequency that last longer than one minute. The IEEE Std. 1159-1995 classifies long-duration variations into three categories:

1. Interruptions, sustained

2. Undervoltages

3. Overvoltages

Long-duration variations are generally caused by load variations or switching operations on the power system.

Voltage Unbalance

Voltage unbalance on a power system is defined as the ratio between the negative- or zero-sequence component to the positive-sequence component. When loads are not balanced, negative- or zero-sequence currents can flow in the power system, causing the voltage to become unbalanced.

Typically, the source of voltage unbalance is an unbalance of single-phase loads connected to a three-phase power system or circuit. The unbalances for this condition are generally less than 2%. If the unbalance on a system is greater than 5%, it usuallyindicates that a single-phase condition (loss of one phase on a three phase system) may exist on the power system.

For transmission systems, it is highly unlikely that voltage unbalance would be caused by single-phase loads because these types of loads are not served from transmission-level voltages.

Abnormal system conditions, such as a blown fuse in a capacitor bank, can result in voltage unbalance on a transmission system. Figure 3-4 and Figure 3-5 illustrate trends of the zero-sequence voltage unbalance and the negative-sequence voltage unbalance, respectively.

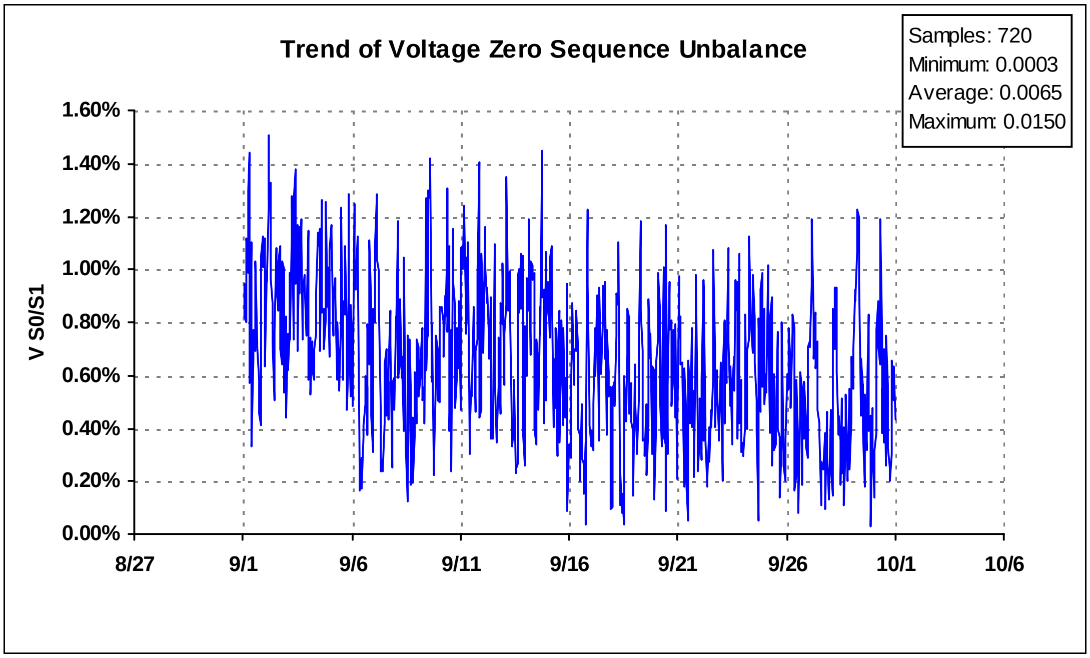

Figure 3-4
Trend of the Zero-Sequence (V0/V1) Voltage Unbalance for a One-Month Period

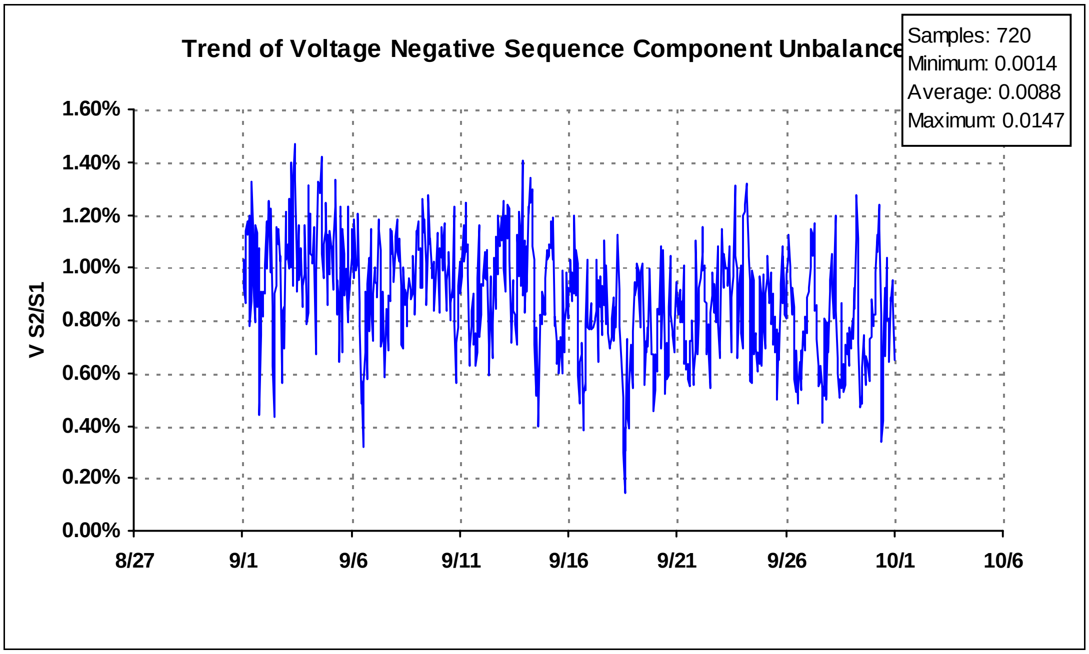

Figure 3-5
Trend of Negative-Sequence (V2/V1) Voltage Unbalance for One-Month Period

Waveform Distortion

Waveform distortion can be defined as any deviation of the power frequency from an ideal sine wave during steady-state conditions. Waveform distortion is typically characterized by the spectral content of the deviation. The IEEE Std. 1159-1995 defines five primary types of waveform distortion:

1. DC offset
2. Harmonics
3. Interharmonics
4. Notching
5. Noise

Examples of each type of waveform distortion are given.

DC Offset

When DC is present in either the voltage or current on an AC power system, it is defined as DC offset. Basically, when viewing a waveform where DC is present, the DC component will shift or offset the AC signal from the zero value of the time axis, as illustrated in Figure 3-6. In Figure 3-6, the original sine wave has been offset by a DC component with a magnitude of 15% of the fundamental 60-Hertz component. While this amount of DC is relatively easy to see when compared to the original signal in our example, in actual measurements it may be necessary to perform a Fourier transform on the signal to ascertain whether the measured signal has a DC component.

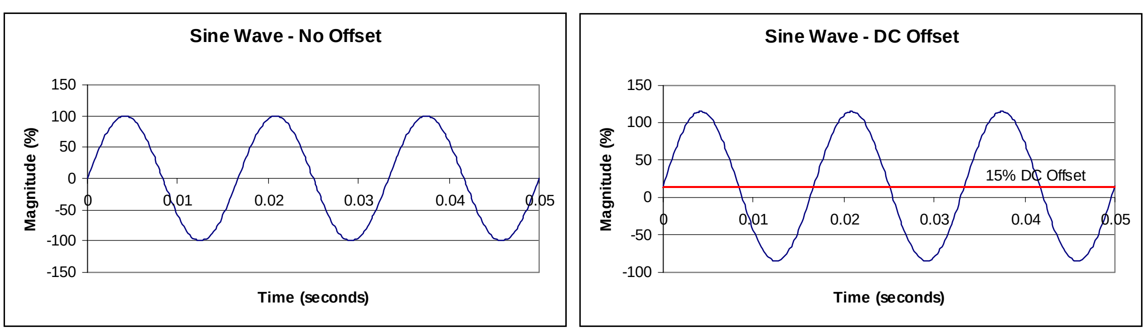

Figure 3-6
Example Plots Showing a 15% DC Offset

The presence of a DC component in an AC signal will produce even harmonics in the spectrum for that signal. The even harmonics are produced as a result of the Fourier transform and the fact that the AC signal is not symmetrical around the time axis. However, the presence of even harmonics does not always indicate the presence of a DC component.

DC offset can occur as a result of half wave-rectification or geomagnetic disturbances known as geomagnetic-induced currents (GIC). The presence of DC in an AC system can have disastrous effects. Transformers can fail due to an increase in saturation levels, and insulation can be stressed due to the DC currents.

Harmonics

Harmonics are sinusoidal voltages or currents of frequencies that are integer multiples of the power system fundamental frequency. When the harmonic voltages or currents combine with the fundamental power system voltages or currents, they produce waveform distortion. Figure 3-7 illustrates waveform distortion. The waveform and associated spectrum in Figure 3-7 represent the input current to a six-pulse AC adjustable-speed drive (ASD).

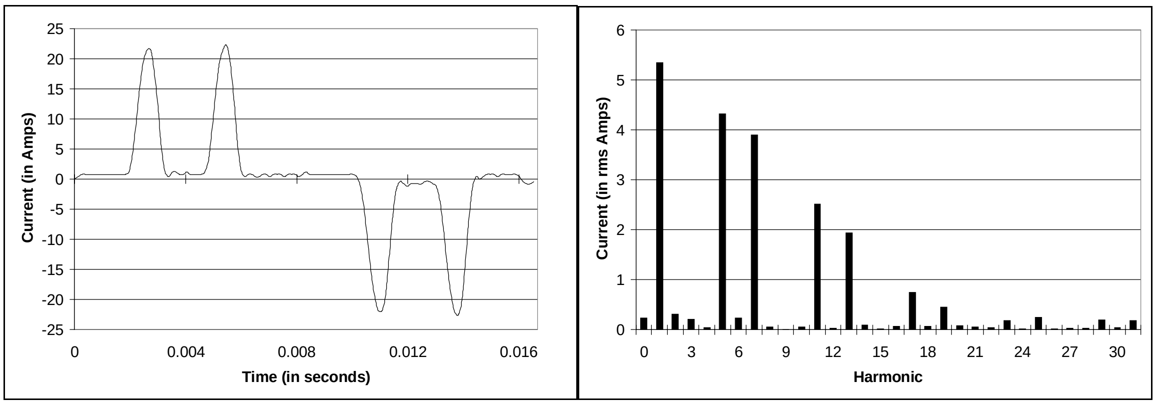

Figure 3-7
Example Illustrating Harmonic Distortion Caused by an AC ASD

In general, utilities produce sinusoidal voltages at the generating plants. When nonlinear loads draw current through the power system, nonlinear voltages are developed. The IEEE Std. 519-1992 includes guidelines to assist utilities in the control of harmonic distortion. IEEE Std. 519-1992 places the burden of harmonic voltage control on the utility and the burden of harmonic current control on the customer. If the customer draws harmonic currents within the limits set forth in IEEE 519-1992 and the utility maintains the power system such that resonances are avoided, the voltage distortion on the power system should remain within the limits set forth in IEEE 519-1992.

Interharmonics

Interharmonics are a special case of harmonics. As opposed to harmonics, interharmonics are not integer multiples of the fundamental power frequency. Interharmonics are a result of the operation of devices such as cyclo-converters, inductions motors, and arcing devices (for example, arc furnaces, magnetic ballasts, and welders).

Notching

Notching occurs due to the normal operation of power electronic devices. When power electronics of a rectifier operate properly, the current is commutated from one phase to another phase, causing a momentary short circuit between the two phases. This produces notching in the voltage waveform similar to the example illustrated in Figure 3-8. Notching is classified as a waveform distortion. The notching occurs continuously and is therefore characterized by the harmonic spectrum of the voltage. Given the frequency components associated with the notch, it may be difficult to characterize the frequency of the notching with standard harmonic-measuring instruments.

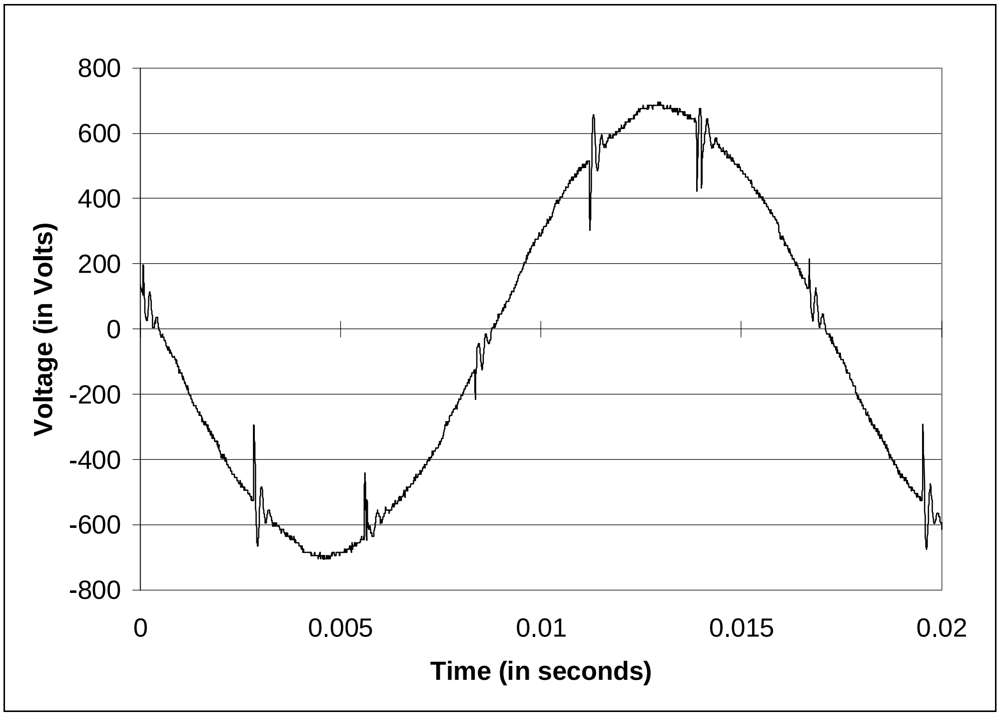

Figure 3-8
Voltage Notching Caused by a DC Drive

The depth of the notch depends on source inductance and the amount of isolating inductance between the drive terminals and the location of the monitoring equipment. Voltage notching is described in great detail in the IEEE Std. 519-1992.

Noise

Electrical noise is unwanted signals that are superimposed on the power frequency. The spectral content for this noise is typically less that 200 kHz. The most common sources of electrical noise are arcing loads and power electronics. Loose connections or improper wiring can often intensify a noise problem. High-efficiency electronic ballasts and dimmer switches are known to produce noise on the wiring of residential buildings. Figure 3-9 illustrates an example of noise measured on a power system.

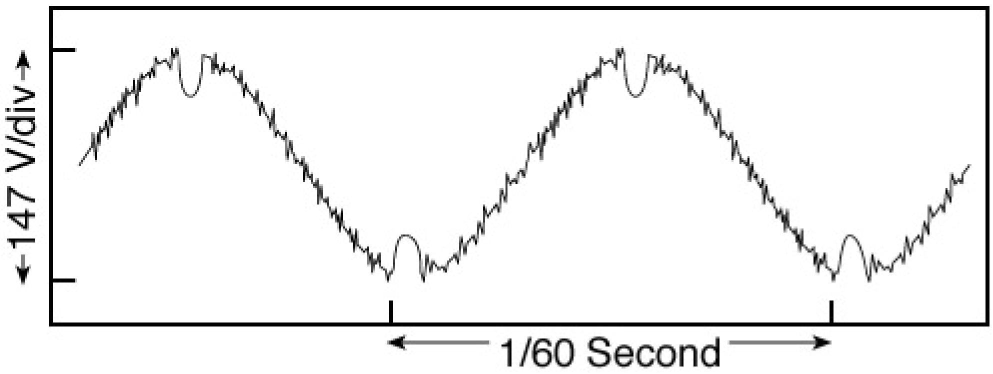

Figure 3-9
Example of Noise Measured on a Power System

Noise on the power system is capable of disrupting electronics devices such as computers, interfering with the operation of infrared (IR) remote controls, and producing horizontal bars or "snow" on television screens.

Voltage Fluctuations

Voltage fluctuations can be either variations of the voltage envelope (slow) or sudden changes in the voltage magnitude. Typically, the magnitude of these changes stay within the guidelines set forth in ANSI C84.1-1989. Voltage fluctuations are typically caused by sudden changes in the load current. Sudden, rapid, and continuous changes in load current can cause voltage fluctuations that in turn cause lights to "flicker." Flicker is nothing more than the effect that voltage fluctuations have on light intensity. Figure 3-10 illustrates an example of a slow voltage fluctuation.

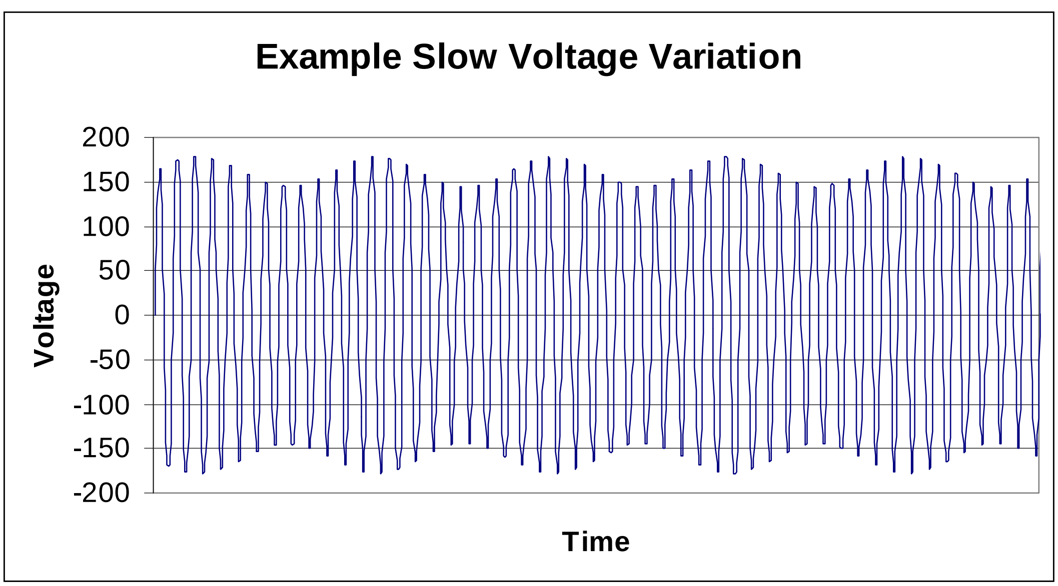

Figure 3-10
Example Waveform of a Slow Voltage Fluctuation

As seen in Figure 3-10, voltage fluctuations of this type generally appear as an amplitude modulation of the power frequency. A typical cause of this type of fluctuation on the transmission system is arc furnaces.

The starting of large motors or other heavy loads can cause sudden variations of voltage on the power system. These types of variations can be isolated or repetitive in nature. The amplitude of these sudden changes generally does not exceed 8% of the nominal voltage. In fact, the IEC states that voltage fluctuations of more than 10% of nominal are to be considered voltage sags or swells [2]. An example of sudden voltage variation caused by a motor starting is shown in Figure 3-11.

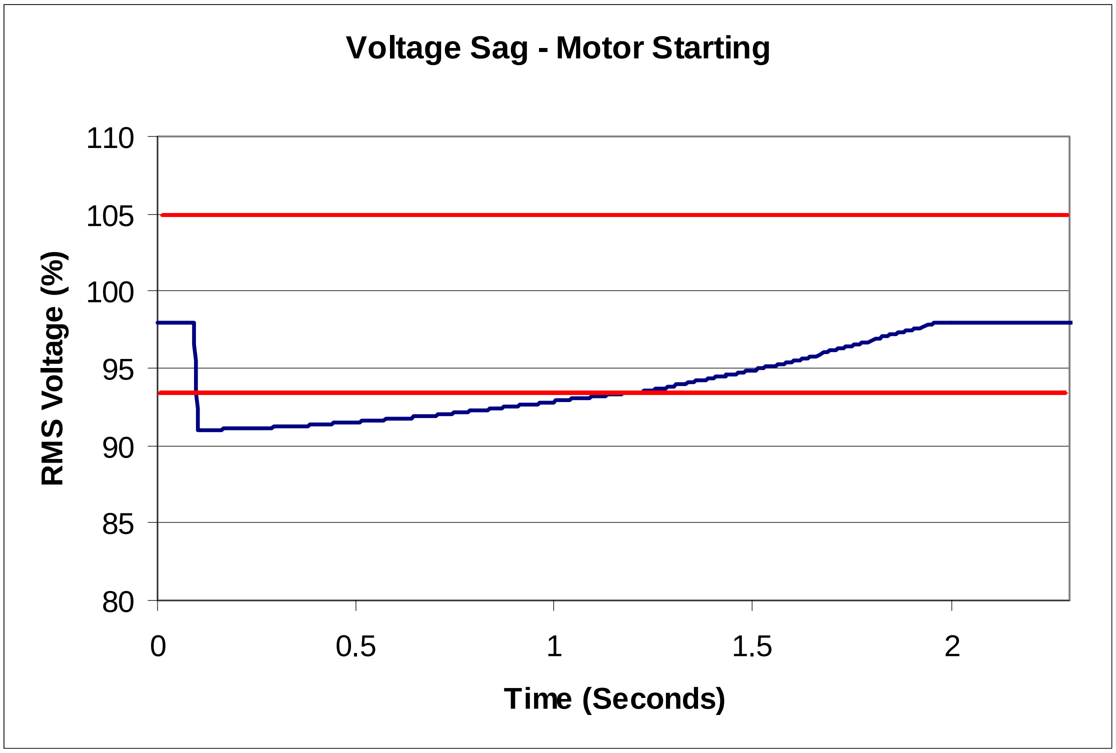

Figure 3-11
Voltage Sag Caused by Motor Starting

Power-Frequency Variations

The frequency of the power system is directly related to the rotational speed of the generators on the power system. In the U.S., the power system operates at a frequency of 60 cycles per second, or 60 Hz. The frequency depends on the balance between the load on the system and the available generation on the system. When the balance between the load and the generation changes, small deviations in the system frequency will occur. The amount of frequency “shift” or deviation from nominal depends on the load characteristics and the response of the system to the load changes.

Faults on the transmission system, a large block of load being disconnected, or a large source of generation going off-line (usually tripping off line) can cause the frequency to fall outside accepted limits. Therefore, it is critical that utilities perform system-stability studies before making any significant changes to the transmission system. These types of frequency variations are rare on an interconnected system like the power system in the U.S. Figure 3-12 illustrates a typical power-frequency variation.

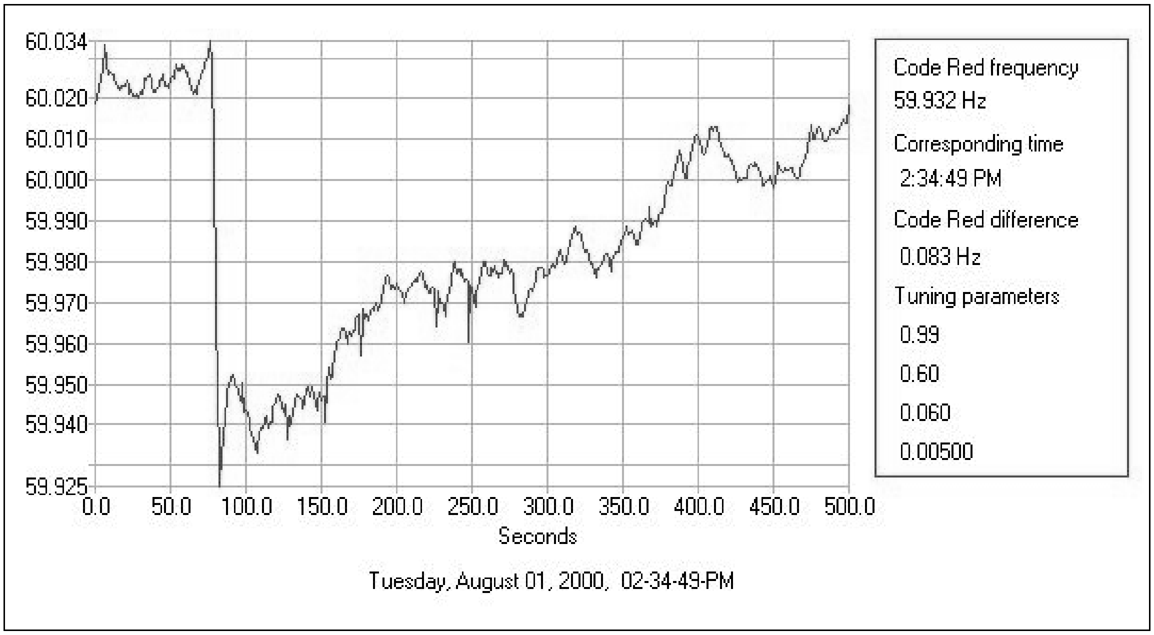

Figure 3-12
Example Frequency-versus-Time Plot for Power-Frequency Variation [3]

Interpretation and Data Analysis

Analyzing power quality measurements has become increasingly more sophisticated within the past few years. It is not enough to simply look at RMS quantities of the voltage and current. Disturbances that occur on the power system have durations in the millisecond time frame, equipment is more sensitive to these disturbances, and there is more equipment connected to the power system that cause disturbances or power quality problems. For these reasons, it is important to have a monitoring system that can capture, store, and evaluate the power quality variations that occur on the power system. This section describes various power quality variations and the methods used to analyze them.

Transients

Transients are normally characterized by the actual waveform, although summary descriptors can be a benefit. Information on the peak magnitude (positive and negative), primary frequency (other than fundamental), time of occurrence, and rise time are often useful pieces of information.

When dealing with large quantities of measurement data, it is preferable to display information for all the events on one type of graph. The most common method for viewing transient information is in the form of a bar graph. Figure 3-13 illustrates a bar graph for transients captured by a power quality monitor.

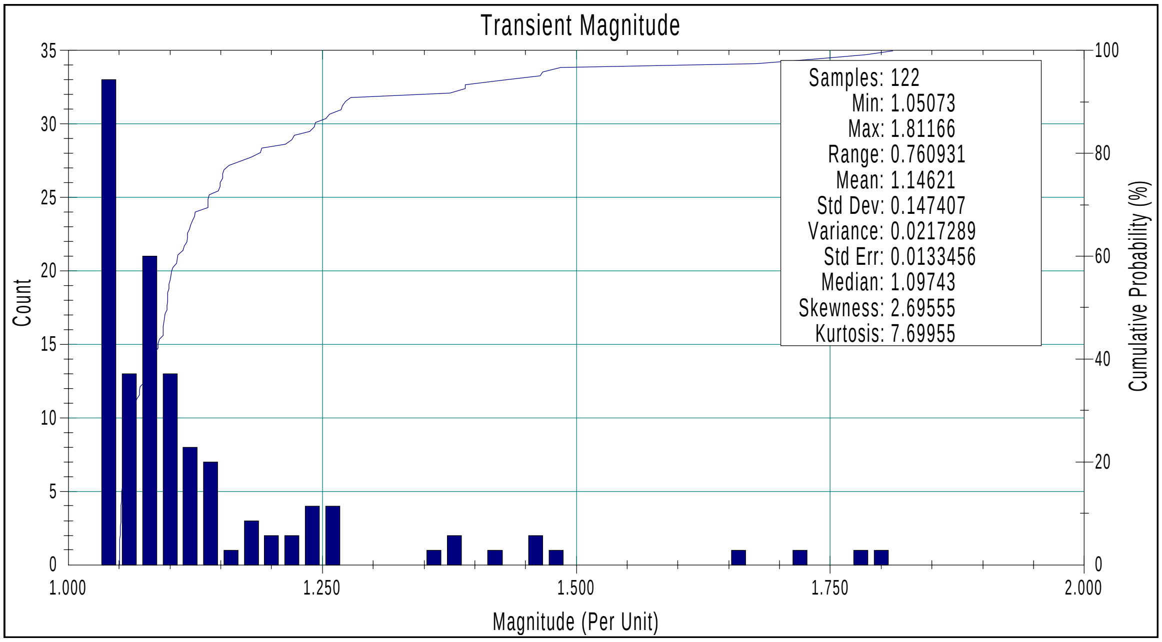

Figure 3-13
Bar Graph Illustrating Transient Peak Voltages

Over 100 events are represented in the graph in Figure 3-13 . Information on the minimum, average, and maximum value of transient magnitude is available in the data block. Other statistical information, as is common with this type of graph, is also available in the data block. The bar graph also contains a cumulative probability curve. By using the cumulative probability curve, the 95th percentile (CP95) point can be determined. The CP95 value tells us the value that was greater than 95% of the other samples. For the data in Figure 3-13, the CP95 value is 1.5 pu. This means that 95% of the 122 measured transients had a magnitude of 1.5 pu or less.

As mentioned previously, another interesting descriptor for transients is the principal frequency of the transient. Figure 3-14 illustrates a bar graph of the principal frequency for the transients in Figure 3-13.

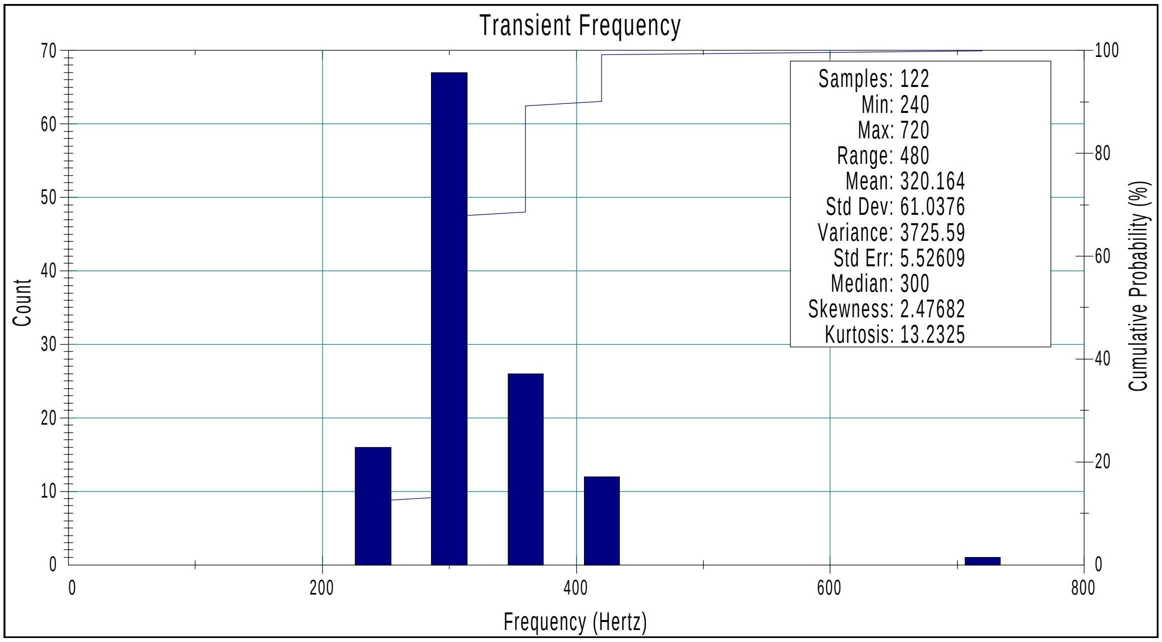

Figure 3-14
Bar Graph Illustrating Principal Frequency of Transients

By using the cumulative probability curve in Figure 3-14, the 80th percentile can be found for the principal frequency to be 350 Hertz. This means that 80% of the measured transients had a principal frequency of 350 Hertz or less.

When analyzing transients, four important characteristics should be determined:

1. The peak magnitude of the transient (both the positive and negative peak).
2. The principal frequency present in the transient.
3. The time that the transient occurred.
4. The rise time of the transient.

These four descriptors are critical for determining the cause and effect of the transients. By having this information, correlations can be made between the measurement data and other system information such as data on lightning, customer complaints, and system operation.

Short-Duration Variations

For analyzing single events, a plot of the RMS magnitude versus time generally characterizes short-duration variations. The time of the occurrence is also good to measure. When an entire system is involved, either customer or utility, it may be preferable to analyze a group of events together. This group may consist of multiple sites for multiple days or just one site for one day. Whatever the case, the data should be presented in an easily understood fashion as illustrated in Figure 3-15, which displays the magnitude versus the duration of events that occurred during a particular time period.

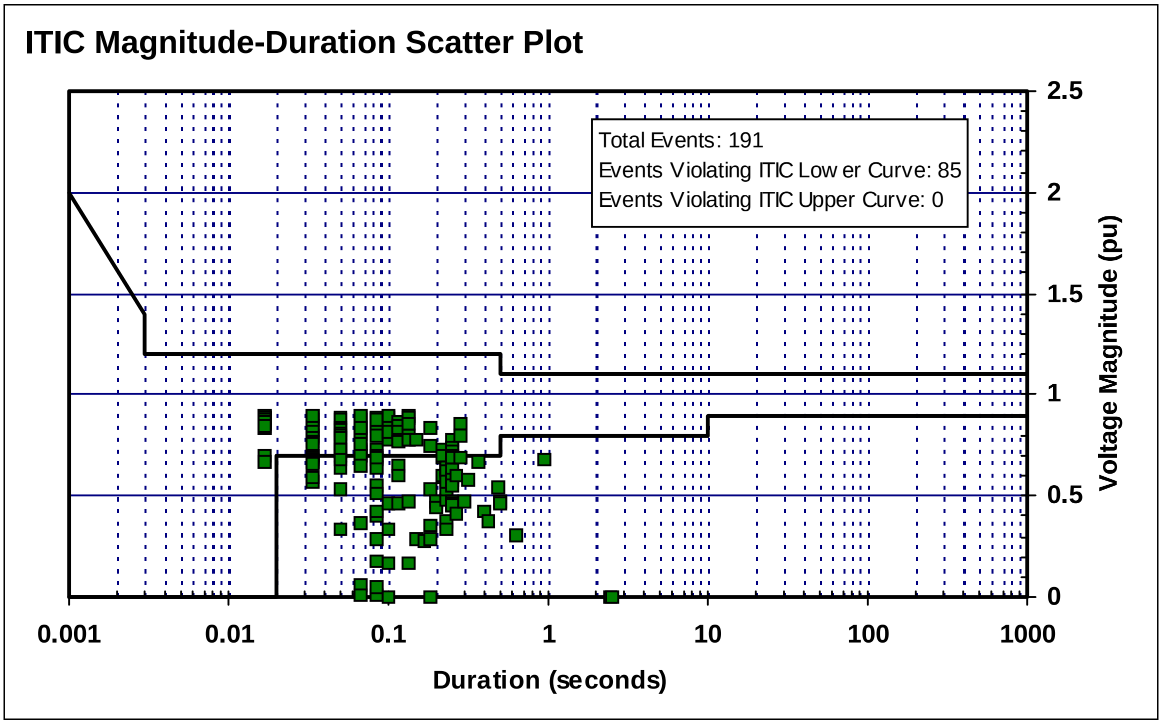

Figure 3-15
Example Magnitude/Duration Plot Used to Represent Voltage Variations (Events are Plotted Against the ITIC Curve)

Using a magnitude/duration plot of this type allows clear identification of many events on one graph. It is easy to see how many events occurred on the power system for the given time period at a particular monitoring site. The magnitude/duration plot in Figure 3-15 shows the time in cycles that voltage was out side thresholds of the monitor) for each event recorded by the monitor. Plots of this type typically include an overlay, such as the ITIC curve, as a reference.

While a magnitude/duration plot allows you to easily see the number of events that occurred during a given period for a given system, the number of events that occurred at a particular magnitude or duration is hard to discern. For this reason, many engineers prefer a three dimensional bar graph where the count, magnitude, and duration are given on the graph. Figure 3-16 illustrates this type of graph.

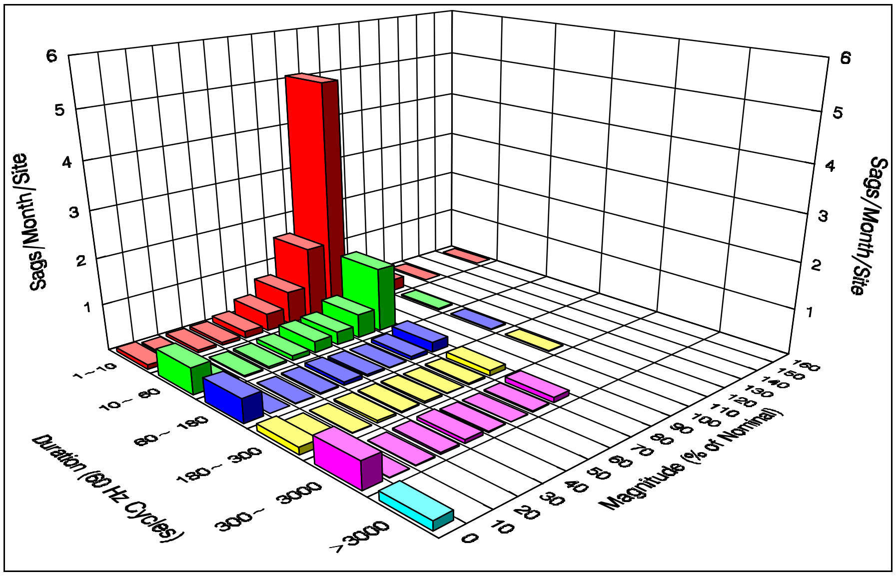

Figure 3-16
Three-Dimensional Bar Graph Used to Represent Voltage Variations [4]

Using the graph in Figure 3-16, one can easily see that the magnitude of a majority of the short-duration variations that occurred on this system was between 60% and 90%. Furthermore, the duration of these same events was less than 40 cycles.

Sag-coordination charts or contour plots [5], as shown in Figure 3-17, are useful tools when analyzing voltage variations. Contour plots present the same type of information as the three-dimensional graphs, but on a two-dimensional plane. Sag-coordination charts are used to show the characteristics of the utility supply and the equipment response to these characteristics. As mentioned, these charts are two-dimensional with the sag magnitude on the abscissa and the sag duration present on the ordinate. Each contour line on the graph represents the number of sags per month.

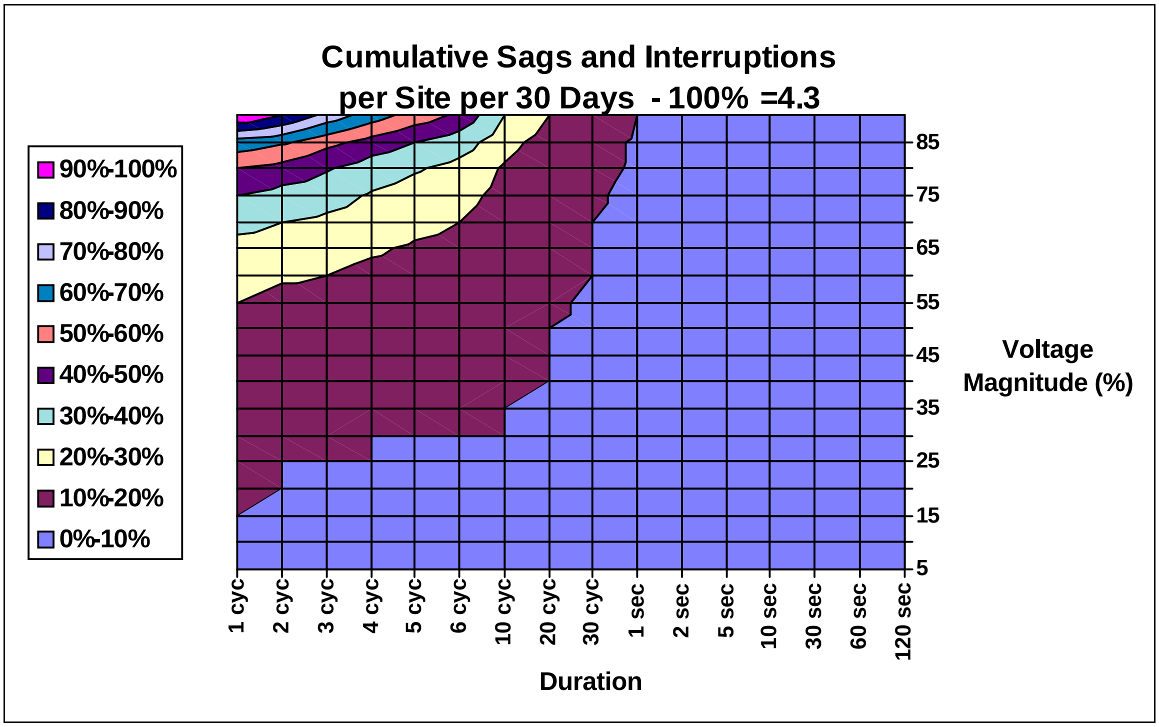

Figure 3-17
Sag-Coordination Chart Used for Displaying Voltage-Variation Data

Sag-coordination charts are used in conjunction with equipment sensitivity curves, which are often rectangular in shape. When an equipment sensitivity curve is superimposed upon a sag-coordination chart, the number of disruptions per month can be determined. Using the chart in Figure 3-18 it can be seen that this particular load could be disrupted 0.86 times per month. The equipment-sensitivity curve in Figure 3-18 (shaded area) shows that for this load, only sags that last longer that 6 cycles and that have a magnitude of 70% of nominal or less will affect this load. To use the chart, the point where the equipment-sensitivity curve touches a contour line must be known. For this case, the equipment-sensitivity curves touches the 20% contour line. To determine the number of sags per year, the total number for the chart (4.3 sags per year) is used and the number of sags can be found by taking 20% of the total or 20% of 4.3, which is 0.86 sags per month.

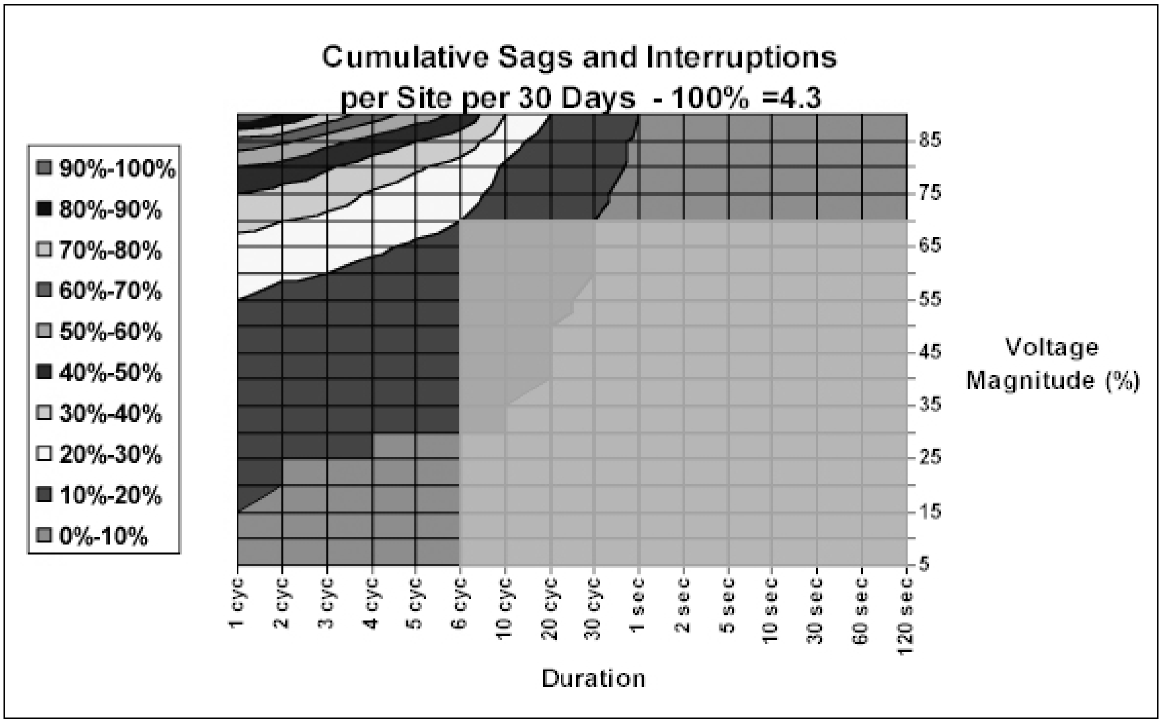

Figure 3-18
Sag Coordination Chart with Equipment-Sensitivity Overlay

Sag and interruption magnitude histograms are useful for analyzing RMS variations. These types of histograms display the “count” or number of times that a monitor recorded a voltage sag in a given magnitude bin. Figure 3-19 illustrates a sag and interruption magnitude histogram. Using the histogram in Figure 3-19, it can be seen that for this monitoring site, historically, there were 1.4 voltage sags measured per 30 days where the voltage was reduced to 90% of nominal. Furthermore, by using the cumulative probability line, it can be seen that the magnitude of 25% of the sags measured at this site was below 60% of nominal.

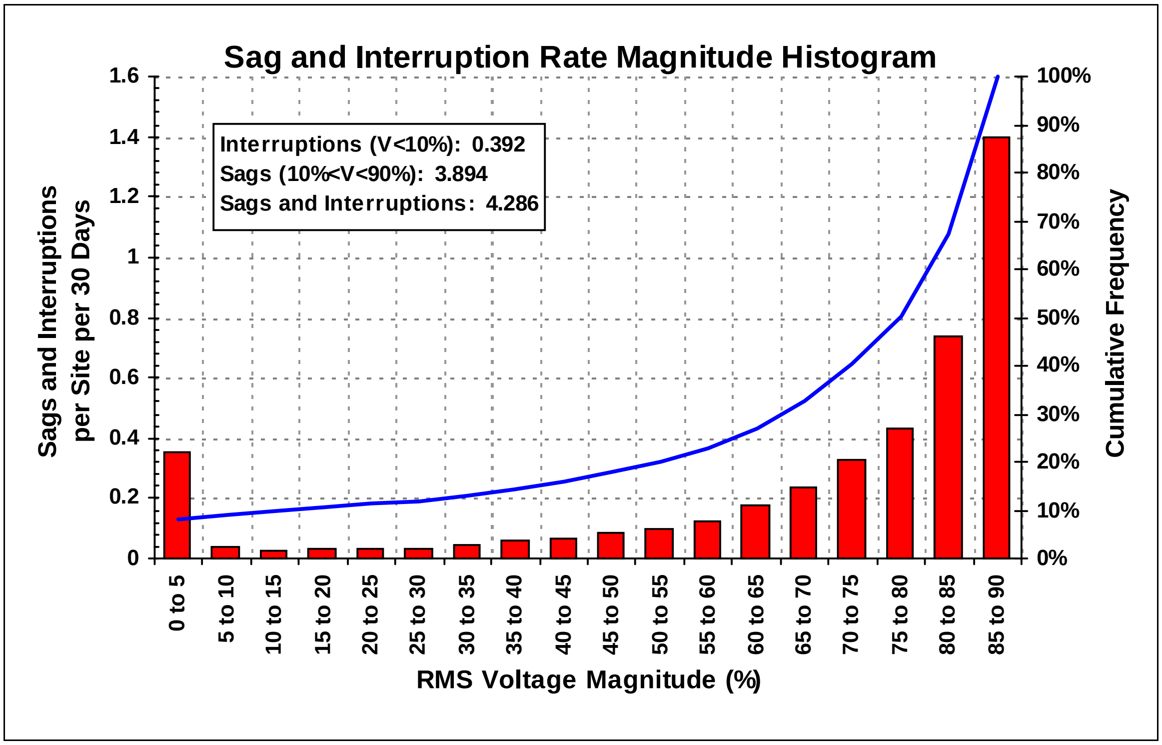

Figure 3-19
Sag and Interruption Rate Magnitude Histogram

Long-Duration Variations

Long-duration variations—variations that last more than a minute, such as interruptions, undervoltages, and overvoltages—are typically characterized by the magnitude and duration of the event. Plots of magnitude versus time are sufficient to characterize these types of events. Tabular data can also be used to determine the severity of long duration variations.

Harmonics

Harmonics is probably the most recognized buzzword when referring to power quality and is probably the most misunderstood phenomenon. All too often, harmonics are blamed for any type of problem occurring in a facility or on the power system. When dealing with harmonics on the power system and, in particular, when trying to analyze harmonics, it is necessary to have a basic understanding of the following terms.

- **Fundamental component.** The first component (50 or 60 Hz) in the Fourier series of a periodic waveform.
- **Harmonic component.** An integer component greater than one of the Fourier series of a periodic waveform.
- **Total harmonic distortion (THD).** The ratio of root-mean-square of the harmonic content to the root-mean-square value of the fundamental quantity, expressed as a percent of the fundamental. Voltage THD is given by Equation 3-1.

$$\%THD = 100 \times \frac{\sqrt{\sum_{h=2}^{\infty} V_h^2}}{V_1} \qquad \textbf{3-1}$$

- **Harmonic number.** The integral number given by the ratio of the frequency of a harmonic to the fundamental frequency.

When dealing with harmonics, the voltage distortion is generally the most important quantity. It is the voltage that will affect other connected loads. Resistive loads will consume more power due to the increased RMS value of the voltage, induction motors will become less efficient due to the counter-rotating torque produced by negative-sequence harmonic voltages, and the timing in digital circuits malfunction due to extra zero-crossings produced by severe voltage distortion.

Normally, simply displaying the waveforms, harmonic spectrums, and THD values for voltages and currents is sufficient when dealing with harmonic measurements. The values are based on a single snapshot of time, and, on occasion, it may be necessary to trend or display the harmonic content versus time. Figure 3-20 illustrates a trend of voltage THD.

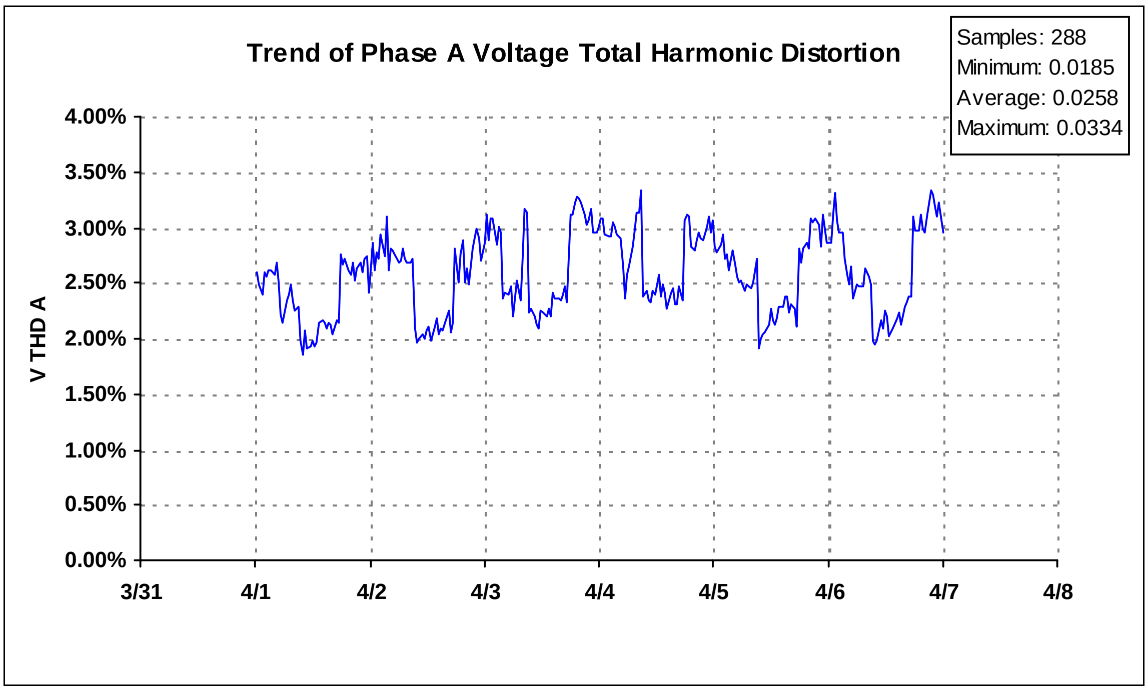

Figure 3-20
Voltage THD Trend for a One-Week Period

As can be seen from the trend in Figure 3-20, the voltage distortion at this site increases and decreases throughout the day and week. In particular, the voltage distortion on the weekends is lower than the voltage distortion throughout the week. This indicates that the process generating the harmonics is not present on the power system during the weekend. It is also apparent from this trend that the harmonic-producing load follows a repeatable pattern throughout the day, coming on in the early morning and going off in the evening (normal work hours).

This type of plot is generally accepted for displaying voltage THD, but when dealing with harmonic currents, it is not. As can be seen from, if the fundamental component changes, then the THD will change proportionally. This is not a problem when dealing with voltages. Most system voltages are regulated within ±5% of the system nominal. Current, on the other hand, changes as the load changes, and THD has little meaning. It therefore becomes necessary to display currents in another format.

Figure 3-21 illustrates the harmonic RMS current (RMS current minus the fundamental) measured on a power system. By using this type of plot, two distinct levels of harmonic current injection can be seen on this power system. One level centers around 17 amps RMS, and the other level centers around 26 amps RMS.

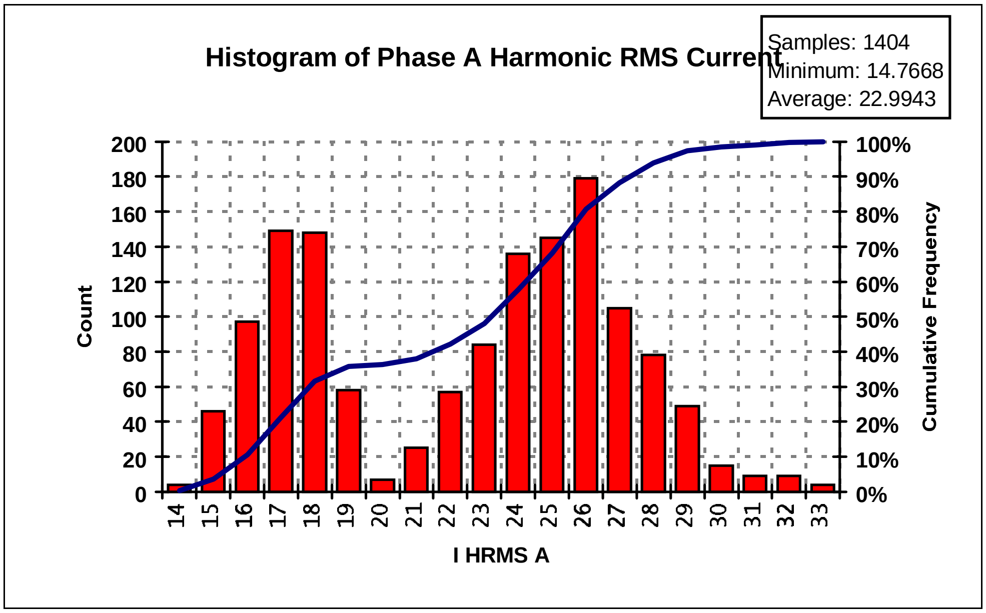

Figure 3-21
Harmonic Current Histogram for a One-Month Period

By developing a trend of the current THD for the same period and monitoring site, the graph in Figure 3-22 would result. This graph is of little value except to obtain minimum and maximum values of the current THD. Without knowing the fundamental current for each data point, the values presented in the THD trend have little meaning.

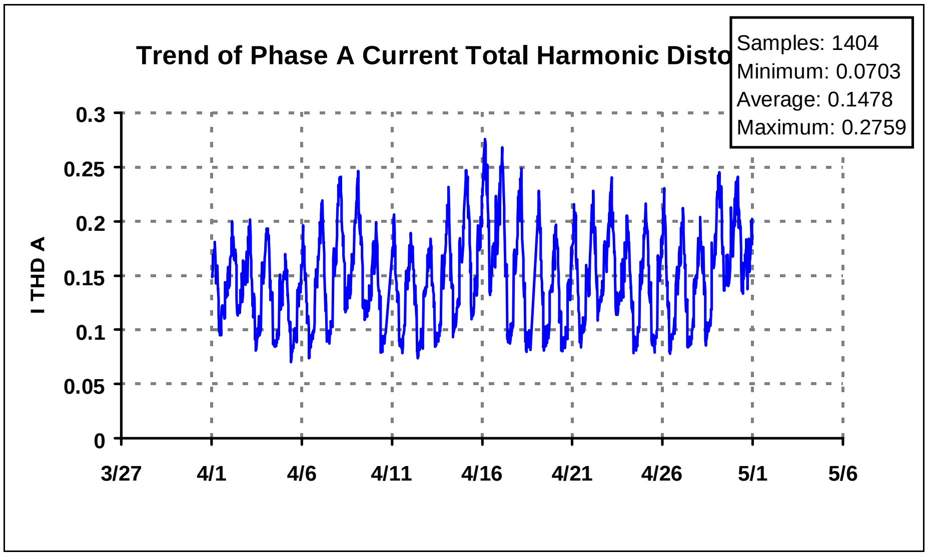

Figure 3-22
Harmonic Current Trend for a One-Month Period

If a trend were required, it would be better to trend the harmonic amps or the total demand distortion (TDD). Figure 3-23 illustrates a one-month trend of the harmonic current. The average harmonic current injection at this site is on the order of 20 to 30 amps RMS.

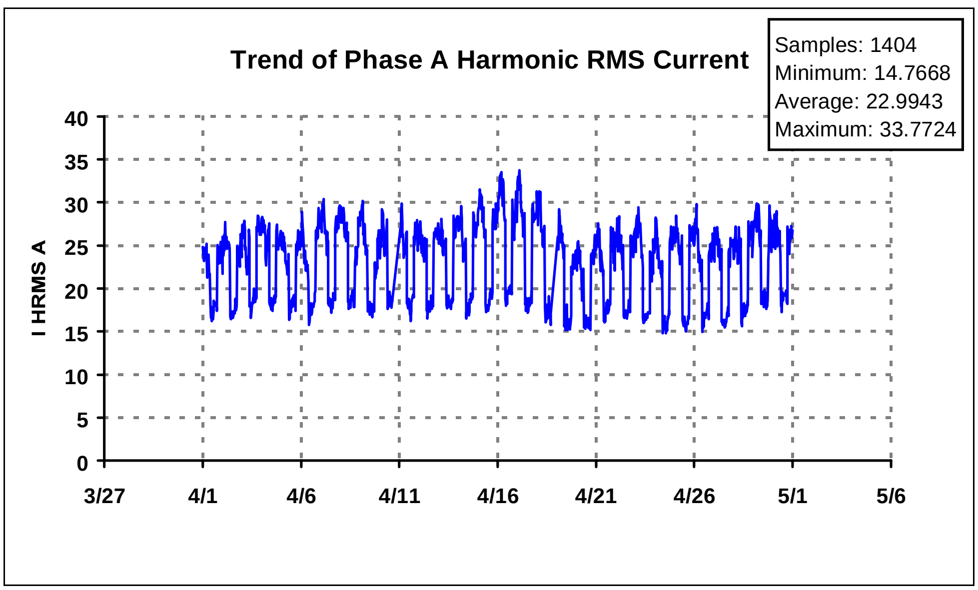

Figure 3-23
Trend of the Harmonic Amps for a One-Month Period

By trending the TDD, the harmonic currents would be normalized to a constant rather than the fundamental, which is constantly changing. In this case, the RMS value of the fundamental would be required for each data point. The plot would look very similar to the trend in Figure 3-23 except that it would be displayed in percent of the maximum demand current as outlined in IEEE Std. 519-1992.

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3. Graphic taken from the Frequency Monitoring Station (FMS) web site located at: http://www.ece.utexas.edu/~gonbeau/. Mr. Olivier Gonbeau and Dr. Mack Grady, ECE Dept., U. T. Austin, maintain the web site, October 2000.

4. Melhorn, Christopher J., and Mark F. McGranaghan, "Interpretation and Analysis of Power Quality Measurements," *IEEE Transactions on Industry Applications,* Volume 31, Number 6, November/December 1996, Pages 1363 - 1370.

5. IEEE P1346, Recommended Practice for Evaluating Electric Power System Compatibility with Electronic Process Equipment, Draft 4.3, October 1997, Pages 35-41.

4
SITE SELECTION FOR DATA COLLECTING EQUIPMENT

Typical goals for a benchmarking project are comparative in nature. Comparisons will generally be made over time and/or by characteristic. The characteristic may be geographical, environmental, voltage level, line design, ownership, or other issue. In order for characteristic comparisons to be meaningful, it is necessary to have enough data-collection points within each characteristic category to be representative of that category. Therefore, optimum site selection requires a clear understanding of what are the most useful and/or practical characteristic comparisons to make.

When evaluating site selection for transmission power quality monitoring, it is first important to recognize all of the pre-existing data-collection equipment that can be used for this purpose. The data available for collection may be as simple as an operator's hand-written log that documents transmission line outages or as sophisticated as a "COMTRADE" data file containing detailed power quality data. The most common data-recording instruments that may already be present include sequence of event recorders, voltage recorders, digital fault recorders, and specialized power quality monitors.

In addition to making use of the pre-existing data-collection equipment, it is important to take advantage of any existing instrument transformers. Data collection at transmission voltage levels tends to be expensive because of the auxiliary equipment required to scale the voltage and current signals down to values that can be connected to data-collecting equipment. Instrument transformers are almost always present at transmission substations because they are required for other purposes such as metering and relaying. Not all of the existing instrument transformers will be suitable for collecting all types of power quality data, as will be explained in the "Transducer Requirements" section.

The site-selection process also depends upon which of the benchmark parameters are being quantified. Some of the benchmarks with specific considerations in this area are outlined below.

RMS Voltage Variations

RMS voltage variations are a fundamental benchmark parameter and ideally would be available at every transmission bus. Even though the equipment requirements to capture this information are rather basic (digital fault recorders fed from either PTs or coupling-capacitor voltage transformers (CCVTs) are generally sufficient), it is not very likely that this equipment would be available at every bus. Fortunately, it is often possible to calculate the RMS voltage variations at every bus for each recorded fault condition. This is accomplished by using the transmission system short-circuit model, transmission line-interruption statistics, and a limited number of recorded voltage-variation profiles for each recorded fault condition. This greatly reduces the required number of RMS voltage-variation monitoring points.

It is anticipated that reasonably accurate RMS voltage variations could be calculated for each bus if 10% of the buses for each transmission voltage level were equipped with monitoring equipment sufficient to record RMS voltage variations. The distribution of these monitors should be somewhat uniform from a geographical point of view in order to provide a variety of “electrical closeness” between the recorder and the fault for each fault condition.

Transmission Line-Interruption Statistics

Transmission line-interruption statistics should be recorded for each unscheduled outage/opening of a transmission line. This is most likely already being done either with recording equipment, manual logs, or a combination. Site selection most often becomes a consideration for this benchmark when it is desired or required to “upgrade” the existing method to a more accurate or automatic system. In this case, the priorities should go to those substations with the least accurate systems. Superimposed on this consideration is the identification of the most important or critical lines, often from a system-integrity point of view.

Voltage Transients

Voltage transients by their nature tend to attenuate rapidly across the system, so unless a recorder is electrically nearby, there is a good chance that the event will not be recorded. Voltage transients caused by switching can be anticipated, so a good site-selection strategy would focus on locations where switching is going to be taking place. A good example of this would be to have an appropriate monitor electrically close to switched capacitor banks. If the capacitor bank is equipped with a synchronized closing switch, the monitor could identify when maintenance or adjustments are necessary for the switch.

A site-selection strategy should also allow for those cases where certain equipment may have less transient-withstand capability or where the equipment is particularly important to the system. A monitor on the high side of a generating station main power transformer is a good example for the “important piece of equipment” strategy. Such a strategically located monitor could identify any increased voltage-transient duty being imposed on the main power transformer.

Flicker

Flicker is another phenomenon that is best monitored at its source. Certain types of loads such as arc furnaces is well-known to create flicker, so the site-selection strategy for this benchmark should include the identifying all such loads and locating the monitors as close (electrically) to the sources as possible. Similarly, the strategy should also allow for any loads or equipment that are known to be particularly sensitive to flicker. In this case, the monitor would be located as close to the sensitive equipment as possible.

Harmonics

The strategy for monitoring harmonics also follows the same pattern identified for voltage transients and voltage flicker. The site selection strategy should allow for the identification of any known sources of harmonics and/or any sites where equipment may be particularly sensitive to harmonics.

5
SAMPLE DESIGN FOR POWER QUALITY MONITORING ON TRANSMISSION SYSTEMS

Background

The core value of statistical methodology is its ability to assist one in making inferences about a large group (a population) based on observations of a sample of that group. In order for this to work correctly, a couple of things have to be true: The sample must be similar to the target population in all relevant aspects, and certain aspects of the measured variables must conform to assumptions that underlie the statistical procedures to be applied.

Representative sampling is one of the most fundamental tenets of inferential statistics: The observed sample must be representative of the target population for inferences to be valid. A simple random-sample design is the random selection of members of the population, with each member having an equal probability of being selected for the sample. A stratified random sample ensures that the sample units 'parallel' the population with respect to certain key characteristics that are thought to be important to the investigation at hand.

Overview of Sample Design

In a world of unrestricted resources, a utility interested in measuring power quality on its transmission system would simply install power quality monitors at each of its substations. However, the cost of monitoring all substations is prohibitive. Thus, a utility must limit monitoring to a portion of its system. Results obtained from monitoring at a sample location can be used to infer the power quality levels of the wider population. The monitoring locations included in a study are the sample, and the way in which these locations are chosen strongly influences both the validity and precision of the power quality estimates made for the population at large.

This section describes how to design and select monitoring locations for a power quality study to ensure that valid, unbiased, and relatively precise inferences can be made about power quality for the entire population. It begins with a discussion of the objectives of sample design, and then describes two types of sample designs: simple random and stratified random. The relationship between sample size and statistical precision is presented. Finally, the procedures required to design and select monitoring locations are described in detail.

Objectives of Sample Design

In designing a substation sample, the goal is to estimate power quality for the entire substation population as accurately as possible. To do this, the researcher has two primary objectives. First, it is desirable to produce estimates that are unbiased. This means that the expected value of mean power quality estimates derived from monitoring equals the true mean in the population. To avoid biases, researchers employ random sampling. With random sampling, each substation in a defined population has an equal probability of being selected for the sample. The use of random sampling ensures that the resulting sample is representative of the substation population as a whole, and does not lead to biased estimates of population parameters. It is assumed throughout this report that random sampling methods are employed, so that bias in the ultimate estimates is not a concern.

The second objective is to produce estimates that are precise. In statistics, precision is defined as the percentage deviation of the true (but unknown to the researcher) population mean from the sample mean (which is determined from the monitoring results) at some specified level of confidence.

Statistical precision is a function of two factors: the variability of the underlying population data and the size of the sample. Variability is negatively related to precision: All other things being equal, the more variable the data, the less precise the estimate. Sample size, on the other hand, is positively related to precision: All other things being equal, the greater the sample size, the more precise the estimate.

In designing a sample, the researcher has no control over the variability of the underlying data and must accept it as a given. However, the researcher can increase the sample size to improve precision. In addition, the researcher can employ stratified sampling to improve precision without requiring increases in the overall sample size. The following section describes the relationship between precision and sample size for a number of alternative sample designs.

Simple Random Sampling

As described above, the objective in sampling is to achieve the greatest statistical precision possible in the power quality estimates for a given sample size (determined by the project budget)[1]. In the case of simple random sampling, the formula for statistical precision is given by:

$$r = \left(\frac{\sigma}{\mu}\right) \cdot \mathrm{Z} \cdot \left(\frac{1}{\sqrt{n}}\right) \qquad \textbf{(5-1)}$$

where:

[1] Alternatively, the researcher may have a specific precision target in mind, in which case the goal is to achieve this target with the smallest possible sample (and budget). Or, the researcher may simply want to evaluate how precision and sample size are related, and then use judgment to arrive at a reasonable trade-off between the twin objectives of high precision and small sample size. Although the discussion in this section is from the perspective of a researcher trying to maximize precision, the conclusions regarding the strengths and weaknesses of various sample designs are equally applicable to either of these two cases.

- r is precision for simple random sampling.
- σ is the standard deviation of the variable of interest.
- μ is the mean of the variable of interest.
- Z is the standard normal variate (that is, Z = 1.96 for a 95 percent confidence interval).
- n is the sample size.

Because precision is measured as a percentage of deviation of the sample mean from the true population mean, lower values of r denote greater precision and are more desirable than higher values. For example, an r value of 0.10 means that the true population mean is within plus-or-minus ten percent of the sample mean value, while a value of 0.05 means that the true mean is within a narrower range of plus-or-minus five percent of the sample mean. Thus, the researcher's objective is to develop a design that minimizes r.

Equation 5-1 shows that, for a given level of desired confidence (Z), statistical precision depends on two factors: the variability of the underlying data and the size of the sample. Variability in the data is defined as the ratio of the standard deviation to the mean, or the coefficient of variation. The greater the variability in the data, the lower the level of precision that can be achieved for a given sample size, thus, higher values of r. An example illustrates.

Suppose that a researcher at General Utility wants to design a simple random sample for the power quality monitoring of its substations. The researcher knows the number of substations from General's existing records. However, information is not available on the mean or standard deviation of Q_p[2], the power quality variable of interest, because General has not performed power quality monitoring before. Fortunately, any information that is available and is positively correlated with Q_p can be used. For example, breaker-trip count information is available, which is known to positively correlate with Q_p. Thus, the researcher decides to use breaker-trip count as a proxy for Q_p to estimate the precision levels attainable from samples of varying sizes.[3] Table 5-1 shows statistics on breaker trip count.

Table 5-1
Breaker Trip Count Statistics on General Utility's Substation Population

Number of Substations	Mean	Standard Deviation	Coefficient of Variation
1,274	869	187	0.215

Table 5-1 shows that the distribution of breaker-trip counts over General's 1,274 substations have a mean of 869 per year and a standard deviation of 187. The ratio of the standard deviation to the mean, or the coefficient of variation, is 0.215. With this information, the researcher can calculate the level of statistical precision achievable from any particular combination of confidence level and sample size.

[2] Q_p is a measure of power quality as defined by (1 - %Nominal Voltage) * Sag Duration, and is a measure of "missing" voltage.

[3] After the monitoring has been completed, the researcher can use the PQ information that was collected during monitoring to refine the precision estimates.

Suppose that the researcher specifies a 95 percent confidence level and has a budget sufficient to fund power quality monitoring of 100 substations. Equation 5-1 can then be used to calculate the level of precision in Q_p that is obtainable from a simple random sample. Table 5-2 presents the details of this calculation. A sample size of 100 will yield an estimate of average Q_p that is within plus-or-minus 4.2 percent of the true population average with a 95 percent confidence.[4]

Table 5-2
Precision Calculation Under Simple Random Sampling

Number of Substations	Mean	Standard Deviation	Coefficient of Variation	Z	*n*	*r*
1,274	869	187	0.215	1.96	100	0.042

A precision level of plus-or-minus 4.2 percent may or may not be acceptable to the General Utility researcher, depending upon the importance of the uses to which the power quality information will be put and the associated costs of decisions based upon imprecise estimates. Suppose that the researcher desires a more accurate estimate that is within plus or minus 2.3 percent of the true population mean. As noted earlier, the way to achieve this is to increase the size of the sample.[5] Equation 5-1 can be used to calculate the statistical precision yielded when different sample sizes are used. Table 5-3 shows the results.

Table 5-3
Relationship Between Sample Size and Precision Under Simple Random Sampling

Number of Substations	Mean	Standard Deviation	Coefficient of Variation	Z	*n*	*r*
1,274	869	187	0.215	1.96	100	0.042
1,274	869	187	0.215	1.96	200	0.030
1,274	869	187	0.215	1.96	300	0.024
1,274	869	187	0.215	1.96	400	0.021

Because the sample size enters as a square-root function in the denominator of Equation 5-1, precision improves at a declining rate as sample size is increased. The results in Table 5-3 illustrate that quadrupling of the sample size from 100 to 400 is required to double the level of precision (that is, halve the value of *r)*. Figure 5-1 shows a graphical representation of the relationship between sample size and precision. It is clear from the graph that there are diminishing returns to the improvements in precision that can be obtained by increasing the sample size. Because such increases come at a cost to the utility, there is some point at which the utility researcher decides that the value of the improved precision no longer is worth the additional monitoring cost.

[4] This means that if the process of selecting a random sample, surveying power quality, and estimating Q_p was repeated a large number of times, then the average Q_p estimate would be within 8.4 percent of the true value 95 percent of the time.

[5] Increasing the sample size will increase the cost of monitoring power quality.

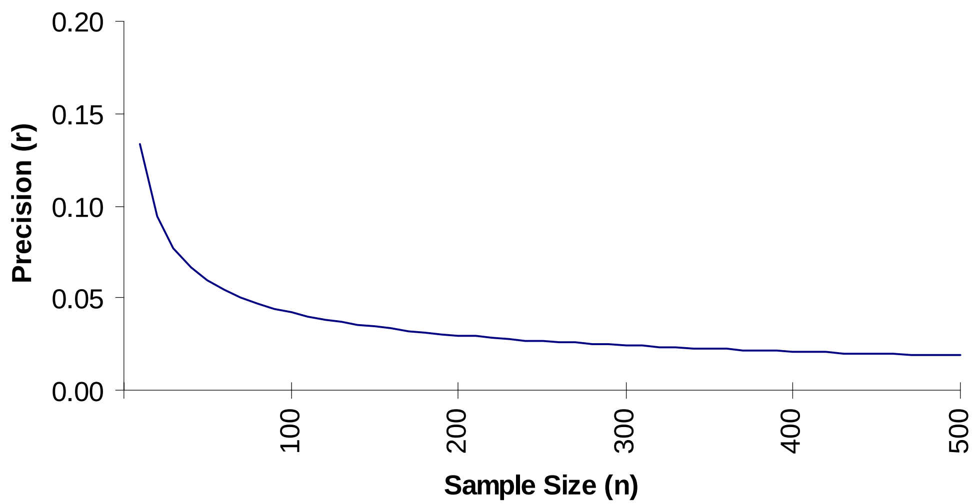


Figure 5-1
Relationship Between Sample Size and Statistical Precision Under Simple Random Sampling

Returning to our example, a sample size of 300 would not be large enough to yield the desired precision level of plus-or-minus 2.3 percent, whereas a sample size of 400 would yield more than the required amount. A sample size somewhere between these two figures would yield the desired level of precision. By rewriting Equation 5-1 to express *n* in terms of *r*, then assigning a value of 0.023 for r, we can we can solve for the minimum required sample size. A sample size of 323 will yield the desired precision level of plus-or-minus 2.3 percent.

Stratified Random Sampling

The example presented in the previous section applies to the situation where the researcher employs a simple random-sampling design. Under this type of design, each substation in the population has an equal chance of being selected for the sample. However, it is generally possible to achieve greater precision for a given sample size by employing stratified sampling designs.

Stratified samples are obtained by segmenting the substation population into a number of groups, known as sampling cells or strata, according to some stratifying variable or set of variables. The strata are homogeneous categories of a heterogeneous population. Gains in precision are achieved by choosing stratification schemes that divide the population into groups with similar power quality characteristics. Intuitively, the improved precision results from the fact that within-group variations in the variable of interest are smaller than the overall variation in the population. As a consequence, sample points can be allocated in a more optimal way among the sampling cells to increase precision without changing the overall sample size.

Continuing with our example, suppose that General Utility's substation population is stratified into three breaker-trip-count groups as shown in Table 5-4. The mean and standard deviation of breaker-trip counts for the overall population are still 869 and 187 per year, respectively, but these statistics vary across the three groups. The important thing to note is that each cell in the stratified design has a smaller coefficient of variation than the overall population, because the cells have been constructed in such a way that groups similar substations together. This is the feature of stratified designs that leads to gains in precision.

Table 5-4
Available Information on General Utility's Substation Population by Sampling Cell

Breaker Trip Count Category	Number of Substations	Mean	Standard Deviation	Coefficient of Variation
Low	265	602	96	0.159
Medium	913	911	104	0.114
High	96	1208	82	0.068
TOTAL	1,274	869	187	0.215

In the case of stratified random sampling, the formula for precision is a bit more complicated than Equation 5-2. Assuming that there are H different sampling cells denoted by the subscript *h*, precision is calculated as:

$$\rho = \left(\frac{1}{\mu}\right) \cdot Z \cdot \sqrt{\sum_{h=1}^{H} \frac{W_h^2 \cdot s_h^2}{n_h}} \qquad \textbf{(5-2)}$$

where:

- ρ is precision for stratified random sampling;
- μ is the mean of the entire sample.
- Z is the standard normal variate ($Z = 1.96$ for a 95 percent confidence interval).
- W_h is the sampling weight of cell *h* (the proportion of the population residing in cell *h*).
- s_h is the standard deviation of the variable of interest within cell *h*.
- n_h is the sample size of cell *h*.

With stratified sampling, the researcher must determine a method for allocating the total number of sample points among the H cells (determine the values of n_h). The two allocation schemes most commonly used by researchers are called proportional and Neyman designs.

Stratified Proportional Designs

One relatively simple way to allocate sample points to the various sampling cells is to do so in proportion to the number of substations in the population that reside in that cell. For example, if 12 percent of the population falls into the first sampling cell, then a researcher using a proportional design would allocate 12 percent of the total sample points to that cell or stratum. Equation 5-3 shows the allocation formula for a proportional design.

$$n_h = N \cdot W_h \text{ for h=1,…,H} \tag{5-3}$$

where:

- n_h is the number of points to be sampled from the h[th] cell.
- N is the total number of sample points.
- W_h is the percentage of total sample points in the h[th] cell.

Returning to our example, recall that using a simple random sample design, the General Utility researcher would have to monitor 323 substations to obtain the desired level of accuracy of plus-or-minus 2.3 percent. However, suppose that the budget available to conduct the monitoring would not support the monitoring of more than 100 substations. Could a stratified proportional design improve precision sufficiently to meet the researcher's objective? Table 5-5 provides the answer.

Table 5-5
Stratified Proportional Sample Design

Usage Category	Number of Substations	Mean	Standard Deviation	Coefficient of Variation	Z	n	Precision
Low	265	602	96	0.159	1.96	21	r = 0.068
Medium	913	911	104	0.114	1.96	72	r = 0.026
High	96	1208	82	0.068	1.96	7	r = 0.049
TOTAL	1,274	869				N = 100	ρ = 0.02275

Under this design, the 100 monitors are distributed among the three sampling cells in proportion to the number of substations in the population residing in each cell. Because the "Medium" category the most substations (72 percent of the substations, 913 out of the 1,274 in total), this cell receives 72 percent of the sample points (72 out of 100). In contrast, the "High" category is allocated just seven percent of the sample points, consistent with its population share. The last column shows the statistical precision resulting from this allocation. The precision varies from cell to cell, but the overall precision, ρ, is improved from plus-or-minus 4.2 percent to plus-or-minus 2.27 percent by moving from a simple random to a stratified proportional design. This is more than sufficient to meet the researcher's 2.3 percent precision target. Attaining an equivalent level of precision from a simple random design would require a sample size of 323 customers.

One primary advantage of a proportional design is that it is easy to implement and will usually result in improved precision over a simple random sample. In addition, a proportional design makes analysis of the resulting power quality monitoring data a relatively simple task, without requiring complicated weighting schemes to extrapolate the sample information to the entire population. However, proportional designs will not generally yield the most precise estimates attainable from a given overall sample size. To maximize precision, the researcher needs to use a more sophisticated design known as a Neyman allocation.

Stratified Neyman Designs

The Neyman allocation is derived by mathematically solving the optimization problem of allocating the total number of samples among the H cells in a way that maximizes precision. This is done by minimizing *r* in Equation 5-4. The solution to this optimization problem is given by the following formula:

$$n_h = N \cdot \left(\frac{W_h \cdot \sigma_h}{\sum_h W_h \cdot \sigma_h} \right) \text{h=1,…,H} \quad \textbf{(5-4)}$$

where:

- n_h is the number of points to be sampled from the h[th] cell.
- N is the total number of sample points.
- W_h is the percentage of total sample points in the h[th] cell.
- σ_h is the standard deviation of the sample points in the h[th] cell.

As Equation 5-4 shows, the Neyman design allocates the total number of sample points in proportion to each sampling cell's population-weighted standard deviation. It is instructive to contrast the Neyman design with its proportional counterpart given by Equation 5-4. With a proportional design, the allocation is entirely dependent upon the population share, W_h. This share is an important factor in a Neyman design too, but it is not the only determinant. A Neyman design also accounts for the variation in the variable of interest within each sampling cell using the cell's standard deviation. By doing so, the Neyman design ensures the greatest level of precision possible from any given sample size.

Table 5-6 shows the stratified Neyman design for our example. A comparison with the proportional design given by Table 5-5 shows that the Neyman design allocates more sample points to the "Medium" category because of its larger standard deviation. The last row in Table 5-6 shows that for this example, the overall level of precision with a Neyman design improves slightly over that yielded by a proportional design. In general, the greater the variation in the standard deviation, the greater the improvement a Neyman design will yield over a proportional design.

Table 5-6
Stratified Neyman Sample Design

Usage Category	Number of Substations	Mean	Standard Deviation	Coefficient of Variation	Z	n	r
Low	265	602	96	0.159	1.96	20	0.070
Medium	913	911	104	0.114	1.96	74	0.026
High	96	1208	82	0.068	1.96	6	0.054
TOTAL	1,274	869				100	0.02271

This example illustrates that gains in precision can be achieved by employing stratified sampling designs. In practice, the magnitude of the improvement in precision depends upon the variability of underlying data and the degree to which the variable of interest is related to the stratification variable. In the case of power quality measures, previous research has shown that it can vary widely across substations. Furthermore, empirical studies have shown that breaker-trip count is at least somewhat related to power quality. Consequently, reasonable gains in precision are generally achievable by stratifying the sample by breaker-trip count.

It is important to note that data on breaker trips may not always be available. Fortunately, any data can be used that is available and is known to positively correlate to the power quality metric being measured.[6]

Sample Selection Procedures

This section describes the procedures to be employed to develop a sample design for monitoring power quality on transmission systems.

1. Define Sampling Frame

The first step in developing a sample design is to define the sampling frame, or the population from which the sample will be chosen. The sampling frame usually corresponds fairly closely to a particular substation class. However, the researcher may want to exclude a certain substation group from the sampling frame because its inclusion would provide information of relatively low value to the utility. Alternatively, the researcher may wish to add a substation group not ordinarily included in the standard definition of the substation class because of a particular interest in that substation segment. The precise definition of the sampling frame should be guided by the ultimate uses to which the power quality estimates will be put.

[6] Further gains may be possible by employing additional stratification variables that are related to PQ. For example, the researcher may wish to use transient data for further stratification. Any variable that is being considered for use in stratifying the populations must meet two conditions. First, the variable should be closely related to the PQ metric to be measured. Otherwise, the gains in precision that result will be small or negligible. Second, the utility must know the value of the variable for every substation in its population, because it needs to exhaustively classify all substations prior to selecting the sample. This second condition eliminates a variable like squirrel population, which may be correlated with power quality but is not known to the utility.

2. Develop Sample Design

Once the sampling frame has been defined, the next step is to design the sample. The design process has four component tasks. First, the researcher needs to identify a stratification variable or set of variables. As discussed above, breaker-trip count can be chosen as a stratification variable. Depending on the availability of other information, the researcher may also wish to choose an additional stratification variable or two.

Once the candidate stratification variables have been selected, the researcher needs to define the boundaries between the cells. For example, if lightning severity is chosen, the researcher needs to determine how many categories there will be and what the break-points will be between them. Similarly, if customer type is used as a stratification variable, then the researcher must decide on the number of distinct customer categories to employ and develop a mapping scheme to uniquely and exhaustively assign substations to a customer category. In the case of continuous variables such as usage, the researcher can employ the Dalenius-Hodges procedure to aid in developing the sampling cell boundaries [1].

The stratification variables and their boundary definitions are, at this point, preliminary. The next step in the design process is to experiment with various alternative stratification variables, cell boundary definitions, and allocation schemes (proportional versus Neyman) to determine the level of precision that would result from each. This process of experimentation involves assigning substations to their appropriate sampling cells and performing calculations similar to those described in the example presented earlier. Specifically, the researcher would calculate the mean and standard deviation of the proxy variables for each cell and then use this information to derive sample allocations and calculate overall precision for various sample sizes and designs. Based on these results, the researcher would specify a final sample design to use for monitoring.

3. Select the Sample

Once the sample design has been finalized, the last step is to actually select the sample. This is a relatively simple process. After all substations in the sampling frame have been assigned to their appropriate sampling cells, the researcher draws independent simple random samples of the desired sizes from each cell. Operationally, this is done in software. For example, n_h substations within each sampling cell are randomly picked, where n_h is the desired sample size in cell h.

Important Stratification Variables

As discussed in previous sections, selecting the proper stratification variables can make the researcher’s job easier when performing site selection. Selecting the stratification variables may seem straightforward, but these variables depend mainly on the power quality phenomenon of interest. A monitoring project that is interested in benchmarking voltage variations will have different stratification variables than a monitoring project geared towards benchmarking harmonics. For this reason, stratification variables are broken into groups that relate to the different categories of power quality.

Transients

As far as transients are concerned, we know from Chapter 6 that transients occur for two reasons:

1. Connection or disconnection of elements on the power system. Capacitor switching and line switching are examples of these types of events.

2. Injection of energy into the power system. Lightning strikes and electrostatic discharges are examples of this type of event.

Therefore, any device on the power system that is connected or disconnected with some regularity should be included in the list. Equipment such as capacitor banks, transformers, and transmission lines are few of the more common pieces of equipment that may cause transients when switched.

Lightning strikes, whether direct or indirect, have the ability to cause transients on the power system. Information on lightning flash density and arrester location is of benefit when conducting a power quality benchmarking study for transients.

The major stratification variables applicable to transients are:

- Capacitor bank (size and location)
- Lightning flash density
- Arrester location and type
- Line switching practices

Voltage Variations

Voltage variations have become the biggest concern for end-use customers and therefore are a concern for the utilities that serve them. Voltage variations can cause process lines to misoperate, which can cause loss of production, employee downtime, and equipment damage. For these reasons, many power quality benchmarking projects are centered around voltage variations of both short duration and long duration.

We know from previous sections in this report that voltage variations are typically caused by three events on the power system:

1. A fault on the power system.

2. Loose connections in wiring.

3. The energization or de-energization of large loads.

Of the three main causes, a fault on the power system is the most predominant cause of voltage variations on the transmission system. For this reason, we need to determine the environmental system and load characteristics that are to be blamed for faults on the transmission system [2].

Of the three main causes, a fault on the power system is the most predominant cause of voltage variations on the transmission system. For this reason, we need to determine the environmental system and load characteristics that are to be blamed for faults on the transmission system [2].

Lightning strikes, whether direct or indirect, inject large amounts of energy into the power system, which can cause a flashover. A flashover causes a fault to occur on the power system, which results in a voltage variation. The distance between the fault and a substation or source affects the depth of the voltage variation.

Major loads being energized on the system also cause voltage variations. Although not as common as lightning strikes, the effect on end-use equipment can be just as severe. Utilities generally plan for large loads on the power system and can avoid the effects of equipment switching.

The major stratification variables applicable to voltage variations are:

- Lightning flash density.
- Voltage level.
- Fault clearing practices.

Harmonics

For harmonics, three factors are important: capacitor banks, their location, and system impedance. The interaction between the power system and capacitor banks on the power system form a parallel resonance on the power system. This parallel resonance produces a high impedance at the resonant frequency. If there are harmonic currents on the power system at that same frequency, high voltages will result at that frequency.

As mentioned in previous sections, nonlinear loads connected to the power system draw non-sinusoidal currents. These currents can, in turn, cause voltage distortion when drawn through the predominantly linear power system. Therefore, the location and size of these types of loads are important when conducting a harmonic study on the power system.

The major stratification variables applicable to harmonics are:

- Capacitor bank (size and location).
- Line and transformer impedance (size and impedance).
- Location and size of major harmonic-producing loads.

Voltage Fluctuations

Voltage fluctuations, by definition, can either be slow or sudden changes in the voltage magnitude. Typically, these changes stay within the guidelines set forth in the ANSI Std. C84.1

and are caused by sudden, rapid changes in the load. For transmission systems, voltage fluctuations can be a big concern.

While most loads are served from distribution systems, transmission systems can serve loads as well. The loads served by transmission systems are usually very large (typically greater than 20 MVA) and can cause voltage fluctuations that are seen or permeate throughout the system. A greater number of customers can experience problems associated with voltage fluctuations on the transmission system because there are many distribution systems served from the transmission system. To compound the problem, the loads served from the transmission system are typically loads such as arc furnaces, whose currents and var requirements can change rapidly and cause voltage fluctuations.

The major stratification variables applicable to voltage fluctuations are:

- Location and size of major cyclical loads.
- The size and location of compensation equipment such as static var.
- Size and location of series capacitors.

Summary of Stratification Variables

The previous sections outlined the major stratification variables of concern as related to specific power quality phenomena. However, when performing a power quality benchmarking study, the results would be flawed if only one power quality category were benchmarked. A comprehensive power quality benchmarking study should include monitoring for all categories of power quality. Every benchmarking study need not be so strict that it encompasses all aspects of every power quality category. Rather, the goals of a benchmarking study should be outlined and followed.

Determining the most important categories to be benchmarked reduces the level of effort placed on the researcher to develop a statistically valid sample. The stratification variables discussed here are meant to be a guide to the researcher. Each power quality category may have more stratification variables than are listed. In fact, depending on the geographic location of the system under test, weather-related and environmental concerns can have an impact on the stratification variables used.

One case where the region of a country and the season plays a factor in the variables that affect power quality is in the Mpumalanga area of South Africa, where lightning and sugar cane fires cause more than 100 voltage sags per year on some systems. The sugar cane fields are burned before the harvest, and the smoke from the fires causes contamination on the transmission towers and insulators [3]. Information such as this is invaluable to the researcher when determining the factors that influence power quality of the system, those factors are related to the environment, power system, or end-use equipment. With all this in mind, the researcher needs to determine, with the aide of engineers, system operators, and end users, the “best” descriptors or stratification variables for the given system and power quality categories that are of interest.

References

1. Dalenius, T., and J.L. Hodges, Jr., "Minimum Variance Stratification," *Journal of the American Statistical Association,* vol. 54, 1959, pp. 88-101.

2. IEEE Std. 1159-1995, *Recommended Practice for Monitoring Electric Power Quality,* IEEE, New York, New York, 1995, Page 15.

3. Cowan, P.M., I.D. Stegman, D. Erasmus, and D.W. McAllister, "Operating Performance of Voltage Dip Mitigation Devices," First Southern African Power Quality Conference, 1996.

6
VOLTAGE-SAG ESTIMATION USING SHORT-CIRCUIT ANALYSIS

Theory

Stochastic prediction methods have been used for years to estimate the reliability of a transmission system and to predict the frequency and duration of sustained interruptions. A stochastic (elemental) approach requires individual small elements of a power system to be individually evaluated. The results of this evaluation are summarized to reflect an estimate of overall system performance. The predictions or estimations made as a result this approach might be that “a customer can expect to experience, on average, 13 voltage sags below 70 percent per year.” This is far different from a prediction of “a customer can expect a voltage sag to 42% at 8:30 PM on May 3rd.”

The stochastic approach typically requires information on the system in the form of a system model and information on historical line performance. The system model typically consists of line lengths, line impedances, transformer information, and short-circuit MVA of the system. Most fault studies typically require this data. Fault studies enable the estimation of system performance to sudden changes in load, such as voltage drop due to a motor start. The available fault current at different points in the system may be calculated for protective-device studies. More advanced fault studies have relay models and recloser and fuse curves, which may be used to perform coordination studies. Data on historical line performance is collected over many years. This data focuses primarily on line performance as it relates to faults on the system. Based on this historical data, an average number of interruptions may be assumed. Usually this data may be categorized to elements of the system such a substation buses, or lines of various voltage classes. The data is expressed in interruptions per year per length (meters or miles) of line. Several fault studies provide a method that enables the user to input interruption data on per-line or per-bus elemental basis.

Advantages

The advantage of using a stochastic prediction method is that estimates about system performance may be made quickly based on readily available system information. Voltage-sag data achieved from fault studies can be very accurate. This is also true for fault-duration data if protective-device models are incorporated into the system analysis. Because stochastic prediction methods rely on modeled and historic line-performance data, estimates may be performed on systems not yet constructed.

Disadvantages

Stochastic prediction methods are only as accurate as the data provided. If the system model is constructed without attention to detail or not maintained with system changes, estimates may be poor. The variable, which is the most subject to change, is the frequency of faults at the system. This variable depends upon season, weather, line-clearance practices, animal contact, and catastrophic events. Therefore, the frequency of events associated with a stochastic estimate may often be a subject of suspicion.

Algorithms

The stochastic "method of fault positions is a straight forward method to determine the expected number of sags [1]." The fault-position method also provides voltage-sag magnitude and duration reference data to a load point of interest (POI). The POI is a reference point in a system where a sensitive load connects to the power system. This method systematically applies faults to the system at increasing distances from the POI to determine voltage-sag magnitude and duration. The number of fault locations evaluated increases the accuracy of the results. The four steps of the fault-position method are:

1. Determine how far from the POI the faults will be applied. In automated studies, the number of faults applied depends on a voltage-sag threshold at the POI.

2. Determine how far apart the faults will be applied. One program provides a menu that allows entry of the number of times a line is divided into fault-application positions.

3. For each fault position, the frequency of faults is determined. This frequency is the expected number of faults, typically on a per-year basis, for the section of the model represented by the fault position. Often the frequency for line sections is determined based on the length of the line multiplied by the average number of faults per mile of line.

4. Faults are repeatedly applied at each fault position using the system model. At each fault position, the voltage sag magnitude and duration as experienced at the POI are calculated.

The results of steps 3 and 4 are associated with fault position, establishing the stochastic information of fault frequency and sag characteristics representing the fault position. Typically, the stochastic data is tabulated and summarized so that the total number of voltage sags associated with a POI and other summary statistics may be calculated.

Examples

Consider the 100-mile line illustrated by Figure 6-1. The model is divided into 8 stochastic elements for fault application with the load POI at the bus on the far left. The choice of fault locations depends on which sag characteristic is of interest. In this case, sag duration and magnitude is under consideration. Note while faults applied to positions 1 and 2 will result in similar sag magnitudes, the duration of the sag at position 1 may differ from position 2 due to protective-device relaying. The line has faults applied at five different locations on the line. Each fault location represents a line segment midpoint. Fault positions 3, 4, and 5 are midpoints for 25-mile segments, while line fault positions 2 and 6 represent midpoints for 12.5-mile line segments.

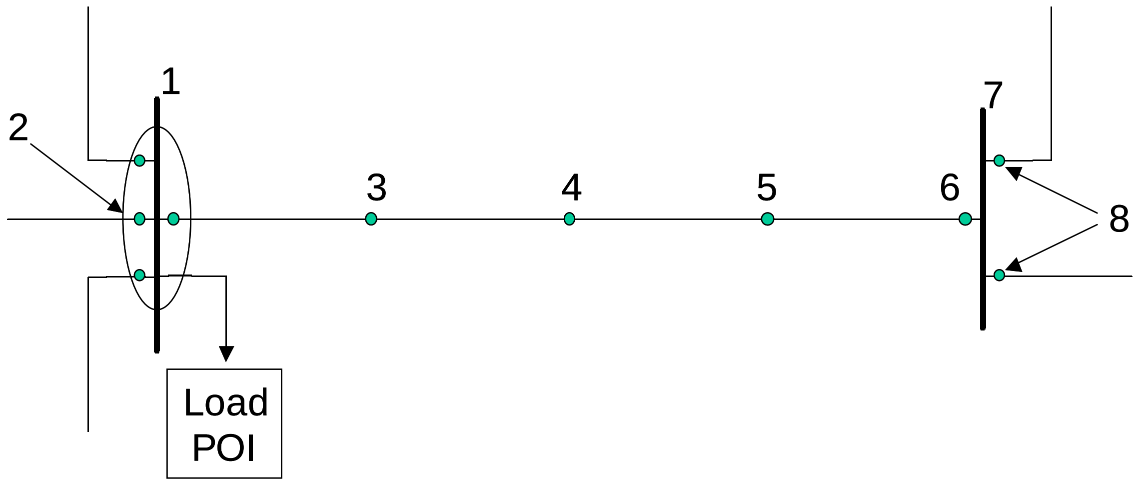


Figure 6-1
Example System with Fault Positions

The stochastic information of fault frequency, sag magnitude, and duration for each fault position is shown in Table 6-1.

Table 6-1
Fault Positions with Corresponding Stochastic Data

	Fault Position	Frequency (Sags per year)	Magnitude (P.U.)	Duration (ms)
1	Fault on local bus serving POI	0.1	0%	180
2	Local close-in line fault (4 lines)	4	0%	80
3	Fault at 25% line	2	31%	90
4	Fault at 50% of line	2	49%	140
5	Fault at 75% of line	2	57%	165
6	Fault at 93.75% of line	1	63%	180
7	Fault on remote bus	0.1	65%	90
8	Remote close-in line fault	2	65%	180

For this example, the utility has historically experienced about 10 faults per 100 buses per year. Therefore, a bus-fault frequency of 0.1 faults per bus per year is applied. Similarly, the frequency of line faults is based on 8 faults per 100 miles of line per year. Once the data from Table 6-1 is achieved, various reports may be generated to describe the system performance from the POI perspective.

Figure 6-2 provides a magnitude histogram used to determine the probability of a sag occurring below a particular value. Another way of displaying this information is in scatter plot where the magnitude of the sag is plotted versus the duration, as illustrated in Figure 6-3.

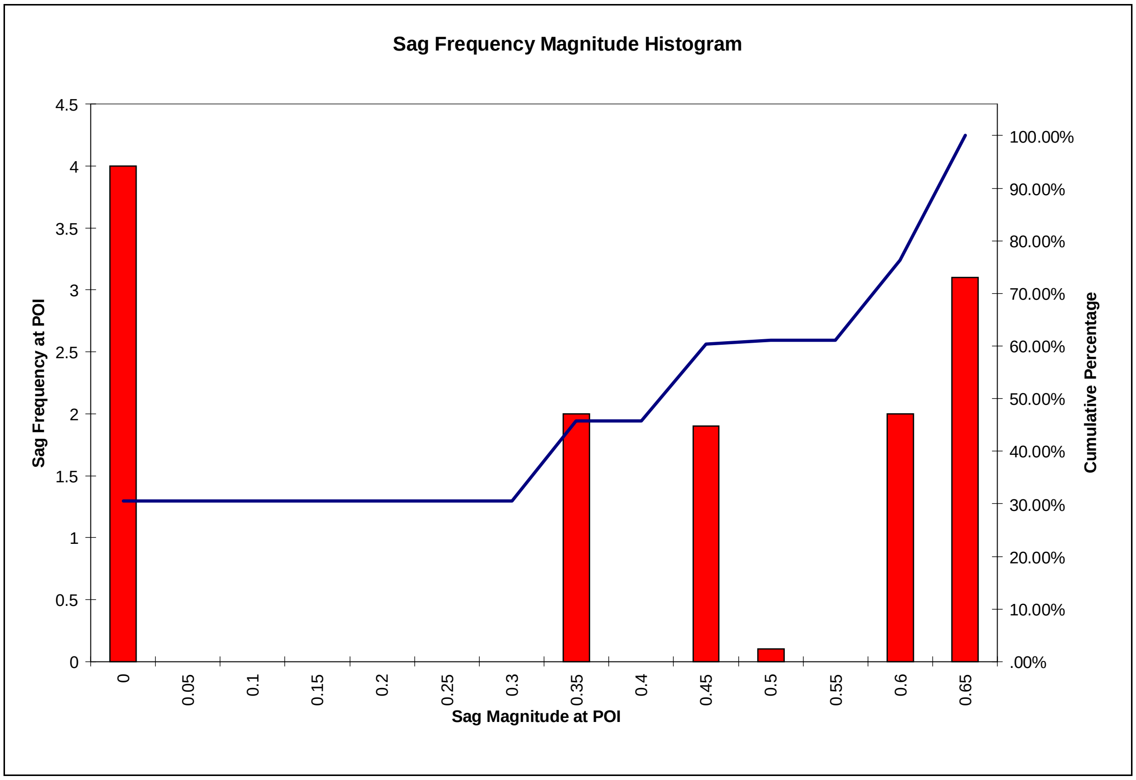


Figure 6-2
Sag Frequency Magnitude Histogram for POI in Figure 6-1

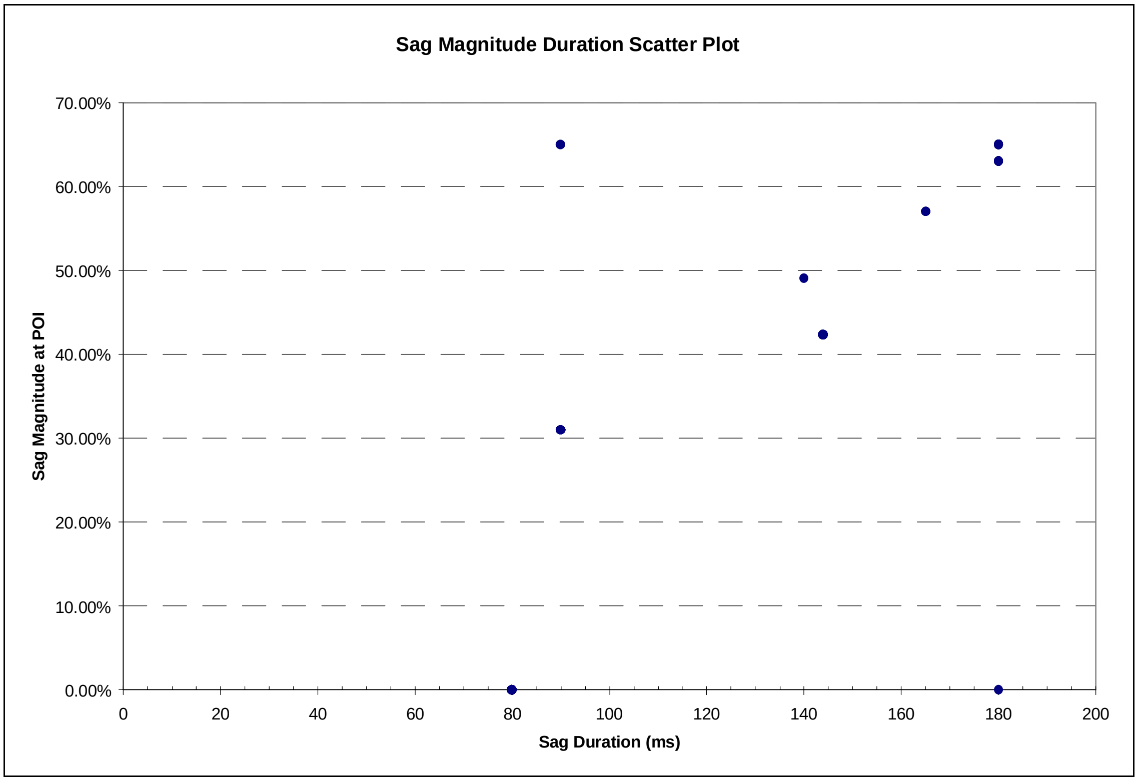


Figure 6-3
Sag Magnitude Duration Scatter Plot of Results in Table 6-1

As seen in the example above, the method of fault positions is relatively straightforward. However, the choice of fault position will influence the accuracy of the results. Obviously, the more fault positions that are chosen, the more accurate the results. There is a point of diminishing return, however. The selection of additional random fault positions will not significantly increase accuracy but will substantially increase computational effort.

The following three decisions must be made when choosing fault positions:

1. Where in the system should faults be applied? For each voltage level, the number of feeders and busses to apply faults to needs to be determined.

2. What should be the distance between fault positions? For each voltage level, this decision needs to be made. Often, distance is based on percentage of line length or the number of fault positions per line.

3. What values are to be considered at each fault position? Typically, voltage-sag magnitude is considered. Another common concern is fault duration. For both sag magnitude and duration, the type of fault must be considered. One might decide only to consider single-phase faults or maybe three-phase faults. Another may choose to consider all possible fault types. The overall study might be performed for different transmission configurations based on generation and load scheduling.

For automated computational means, the distance between fault positions or the number of fault positions per line may be set. However, as shown in Figure 6-4, the larger the distance between the POI and the fault location, the less change there is in voltage-sag magnitudes. The slope of the actual voltage becomes closer to the slope of the approximated voltage, indicating less change in voltage-sag magnitudes between fault positions for faults at increasing distances from the POI. This suggests that fewer fault locations are required as the distance from the POI to the fault is increased.

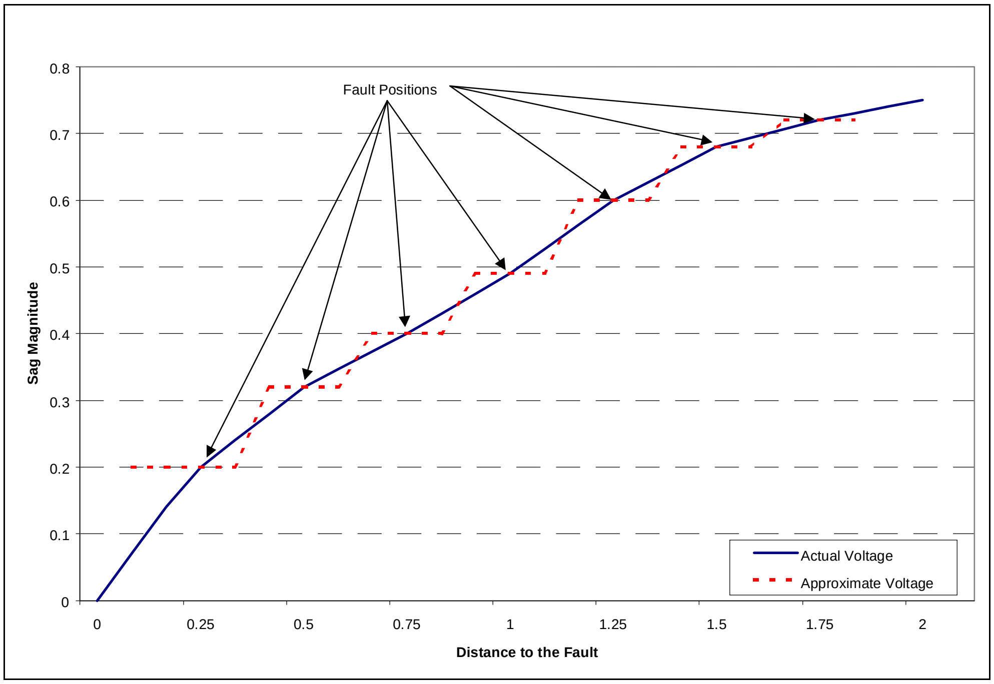


Figure 6-4
Comparison of Actual Voltage Sags to Approximated Voltage Sags

Methodology Application

The stochastic method of fault positions was “probably first used by Conrad whose work has was become part of IEEE Std-493. The method is also used by Edf (Electricit’e de France) to estimate the number of sags due to faults in their distribution system [1].” The following sections discuss three practical variances of the method of fault positions being used in the United States. These three approaches include a cookbook method described in an EPRI document, EPRI software utilizing the output from a vendor’s fault modeling software, and finally an approach made by another vendor’s fault-modeling software where a macro was developed in cooperation with a major power transmission utility in southeastern United States.

Cookbook Method

Determining the performance of a transmission system with respect to a given point of interest is best adapted to system modeling software where iterative calculations may be performed. In EPRI's *Power Quality Workbook for Utility and Industrial Applications* [2], a procedure is presented with example tables. The purpose of the procedure is to calculate the expected frequency and magnitude of voltage sags at a bus serving an end user due to faults on a transmission system.

Step 1: Build a Transmission-Line Fault-Performance Table

This table includes the historical performance information or expected performance for each line section in terms of number of faults expected per year for both single line-to-ground and three-phase faults. Usually, single line-to-ground faults will be the most common. Table 6-2 provides a worksheet that may be used as a format for this table.

Step 2: Calculate the Area of Vulnerability

In this step, short-circuit simulations are performed to determine the voltage-sag severity at a selected system location for fault locations throughout the transmission system. This will identify the fault locations that can cause a voltage sag below the specified threshold. The total circuit miles of possible fault locations that can cause a voltage sag severe enough to cause misoperation of end-user equipment is known as the area of vulnerability (AOV) for that equipment. Table 6-3 is an example of the fault locations (single line-to-ground faults) that can cause voltage sags below 85% of nominal at a specific end-user location.

Step 3: Calculate Expected Number of Voltage Sags that will Cause Equipment Misoperation

The third step converts the area of vulnerability data to actual expected events per month at the specified location. This is accomplished using the area of vulnerability and the expected performance for three-phase and single line-to-ground faults over that area. Summing up the expected number of faults on each line section within the area of vulnerability will give the total expected number of events that can cause equipment misoperation. This information is usually expressed as events that can cause equipment misoperation and in terms of events per month or events per year. Table 6-4 can be used to perform this calculation. Table 6-5 shows the results of these calculations.

Step 4: Calculate Expected Number of Momentary Interruptions

The momentary-interruption performance for a customer due to transmission-system faults should be calculated if the customer is supplied as a tap from a switched transmission line (that is, there are no transmission-line breakers at the customer location). In this case, the expected number of momentary interruptions per year due to transmission events is the expected number of faults (operations) on that line. This should be calculated separately from the voltage-sag performance.

Step 5: Calculate the Expected Performance for Different Equipment-Sensitivity Levels

This will give the end user information that can be used to help develop equipment specifications or to select the appropriate equipment protection. The information can be presented as a histogram, as shown in Figure 6-5, or as a continuous curve of expected number of voltage sags versus the sag severity as shown in Figure 6-6.

Step 6: Evaluate the Effect of End-User Transformer Connections

Single line-to-ground faults on the transmission system will have different impacts at the end-user level, depending on the transformer connections.

Table 6-6 can be used to estimate the voltages on a transformer secondary for a fault on the primary as a function of the connection.

Table 6-2
Sample Worksheet for Transmission-Line Fault Performance

Transmission Line Fault Performance Table

Line ID	Voltage (kV)	From Bus	To Bus	Line Length (miles)	Fault Performance (Faults/Year)	
					SLGF	3 Phase

Table 6-3
Example Area of Vulnerability Calculation for a Specified End User Supplied from the Transmission System

Line ID	Voltage (kV)	From Bus	To Bus	Line Length (miles)	SLG Fault Performance (Faults/Year)	Phase Voltage at End-User Bus (per unit)
1	115	SAL ALU	CHEMAWA	3.30	0.59	0.516
2	115	CHEMAWA	BRUSH CL	8.52	1.54	0.598
3	115	SALEM	BRUSH CL	1.89	0.34	0.746
4	115	HAZELWOOD	ALBANY	0.10	0.02	0.804
5	115	SALEM	MONMOUTH	10.20	1.84	0.826
6	115	SALEM	BETHEL	14.38	2.59	0.829
7	115	HAZELWOOD	FRY	5.90	1.08	0.851
8	115	SALEM	DALLAS	10.10	1.82	0.859
9	115	SALEM	CONSER	17.56	3.17	0.862
21	230	CHEMAWA	BETHEL	10.00	0.99	0.612
22	230	SALEM	CHEMAWA	10.66	1.06	0.722
23	230	SANTIAM	BETHEL	7.00	0.69	0.765
24	230	MONITOR	BETHEL	0.15	0.01	0.813
25	230	SPENCER	ALVEY	1.98	0.20	0.825
26	230	DLS PH6	BIG EDDY	0.96	0.10	0.838
27	230	DALS PH3	BIG EDDY	0.84	0.08	0.841
28	230	CELILO 4	BIG EDDY	0.96	0.10	0.841
29	230	DELILO 3	BIG EDDY	1.09	0.11	0.842
30	230	DALS PH5	BIG EDDY	0.92	0.09	0.842
31	230	DALS PH4	BIG EDDY	0.84	0.08	0.843
32	230	SHERWOOD	BIG EDDY	0.60	0.59	0.843
33	230	MCLOUGLN	GRESHAM	12.20	1.21	0.847
34	230	MONITOR	MCLOUGLN	20.57	2.04	0.850
35	230	PEARL	MCLOUGLN	10.00	0.99	0.851
36	230	FRY	BETHEL	26.24	2.60	0.853
37	230	LINNEMAN	GRESHAM	0.31	0.03	0.857
41	525	SANTIAMV	MARION	2.45	0.05	0.747
42	525	PEARL	KEELER	18.33	0.37	0.776
43	525	PEARL	OSTRANDR	17.84	0.36	0.776
44	525	OSTRANDR	MCLOUGLN	8.22	0.16	0.791
45	525	PEARL	MARION	39.38	0.79	0.792
46	525	CELILO 2	BIG EDDY	0.62	0.01	0.799
47	525	CELILO 1	BIG EDDY	0.72	0.01	0.799
48	525	JOHN DAY	BIG EDDY	18.94	0.38	0.818
49	525	JOHN DAY	BIG EDDY	18.96	0.38	0.823
50	525	MARION	ALVEY CAPS	64.82	1.30	0.825
51	525	TROUTDAL	OSTERNDR	23.79	0.48	0.842
52	525	MARION	LANE	68.97	1.38	0.843
53	525	KEELER	ALSTON	42.35	0.85	0.843

Table 6-4
Worksheet for Calculation of Expected Performance at End User for Specific Magnitude

Location ______________________________

Performance for a Threshold of _______________ %

		Fault Performance (faults/100 mi/year)		Expected Sag Performance (sags/year at specified location)	
Voltage Level	Exposure (miles)	SLGF (FP1)	3 Phase Fault (FP3)	1 Phase (milesxFP1/100)	3 Phase (milesxFP3/100)
TOTAL					

Table 6-5 provides an example calculation for a voltage-sag severity of 75% using the data in Table 6-3 and assumed values for fault performance at the different voltage levels. Note that this calculation uses an average fault-performance level for each voltage class (FP1 and FP3) instead of the historical fault performance for individual lines, as can be listed in Table 6-3. FP1 and FP3 are usually available for the overall system fault performance. Using the fault performance data for individual lines will give a more accurate calculation, but the data may be difficult to obtain.

Table 6-5
Expected Performance for Example Site for 75% End-User Voltage Sensitivity Level

Location Example Site

Performance for a Threshold of 75 %

		Fault Performance (faults/100 mi/year)		Expected Sag Performance (sags/year at specified location)	
Voltage Level (kV)	Exposure (miles)	SLGF (FP1)	3 Phase Fault (FP3)	1 Phase (milesxFP1/100)	3 Phase (milesxFP3/100)
525	2.5	2		0.05	
230	20.7	10		2.07	
115	13.7	8		2.47	
TOTAL				4.59	

Using the information in Table 6-5, it can be determined that if this end user has equipment that is affected by voltage sags of 75% and below, there should be, on the average, 4.6 events per year that will cause the end-use equipment to misoperate. These events would all be caused by single line-to-ground faults on the transmission system. This calculation results in one set of points on the continuous curve in Figure 6-6. The totalized curve crosses the 75% sensitivity level at between 4 and 5 events per year. The individual contributions from different faults at the different voltage levels are also shown. Figure 6-5 is a simplified way to show the same data with only a few points illustrated as a bar chart.

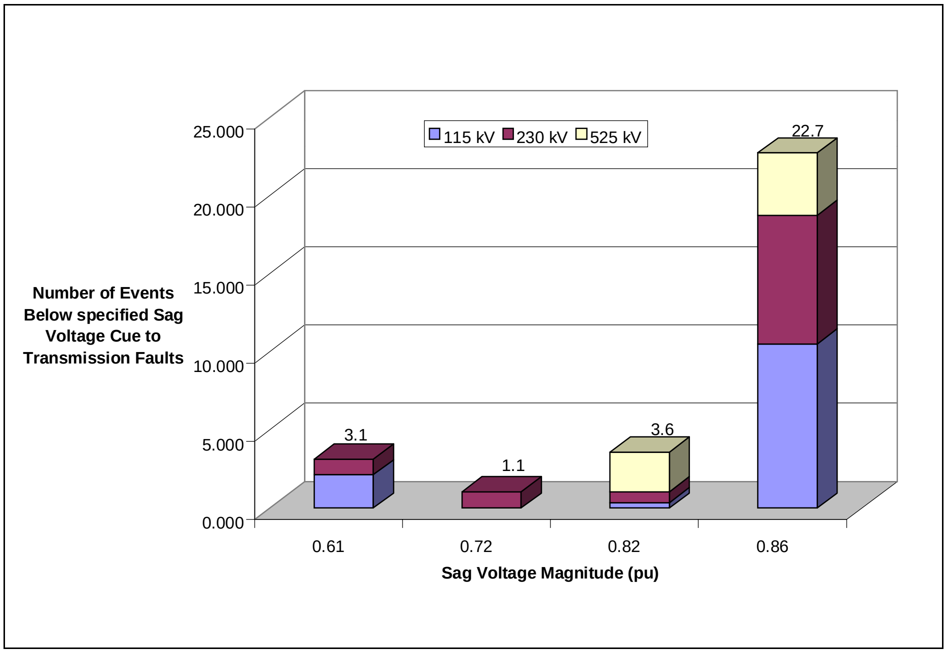


Figure 6-5
Example Histogram Illustrating Expected Number of Voltage Sags at End-User Location for Different Voltage-Sag Severities

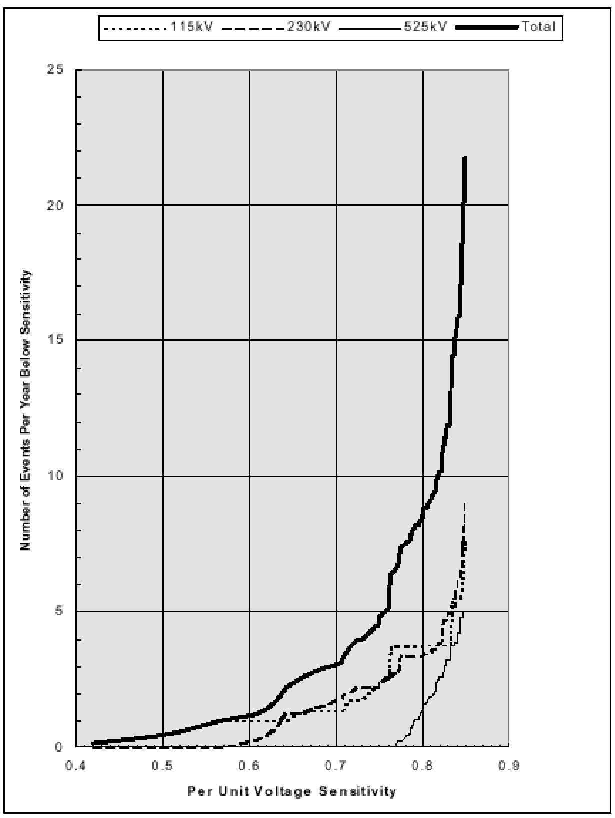


Figure 6-6
Example Voltage-Sag Performance Chart Presented as a Continuous Curve

Vendor's Output to EPRI Software

EPRI developed the Voltage Sag Analysis Module [3] (VSAM) to support Area of Vulnerability (AOV) reporting. The VSAM is also a component of the Integrated Power Quality Diagnostic System (PQDS) [4]. The VSAM relies on a vendor's (ASPEN) fault-modeling software to perform the iterative application of faults on a system model using the method of fault positions. The resulting text file is then used as a starting point for the VSAM software. The VSAM software provides opportunities to add transmission system line performance data and distribution data, including transformer connection information. Once this data is provided, the VSAM software provides an AOV output in the form of a table and chart. In the PQDS software, text output from the VSAM provides data to the Economic Assessment Module of PQDS, supporting the evaluation of proposed sag mitigation.

A brief description of the vendor and VSAM windows follows:

Before the VSAM can be used, a text output file must be generated from the specified vendor program. In order to get the output file, the vendor program provides a data input window as displayed in Figure 6-7.

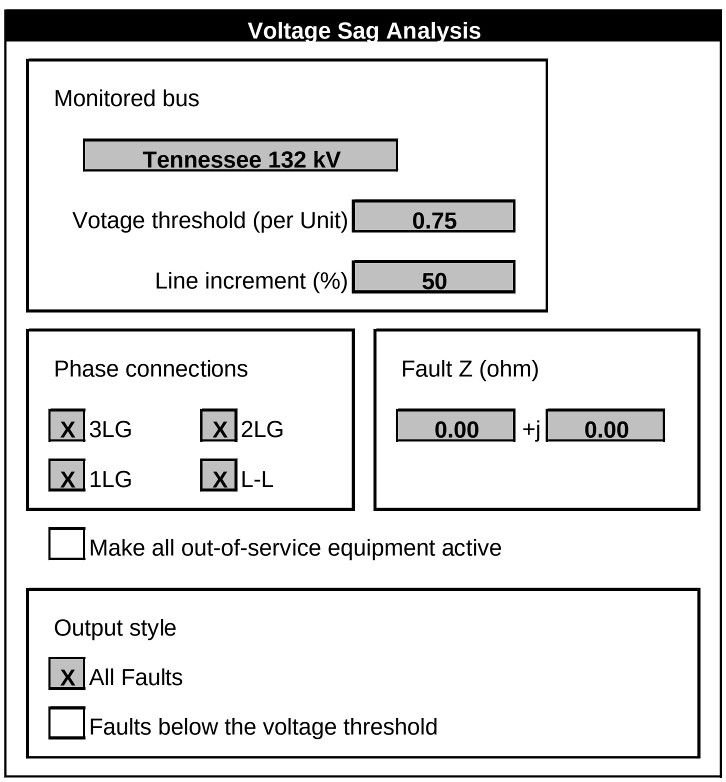


Figure 6-7
Vendor's Data Input Window to Provide Text Output File for Voltage-Sag Analysis Module

In Figure 6-7, the monitored bus is the POI or the bus location of the end-use customer. The voltage at this buss will be tabulated for the various fault positions. The voltage threshold is used to stop the fault simulation if the "Faults below the voltage threshold" in the "Output style" is selected. The “Line increment (%)” instructs the program how many faults to apply to a line. For example, a value of 25% will cause the program to place 3 faults on each line at the 25%, 50%, and 75% positions. One or more fault types may be selected.

- 3LG: three-phase to ground
- 2LG: 2-phase to ground
- 1LG: 1-phase to ground
- L-L: Line to Line

The fault impedance may be specified in “Fault Z (ohm).” The VSAM requires the “Output style” to be “All Faults.”

Once all the selections are made, and the user confirms the selections, the program provides a dialog box asking for the output file name. After the name is entered, the program runs a batch file that writes the results to the file name specified by the user. This file name must have the “*.out” extension to be read by the VSAM.

After the VSAM imports the *.out file created by the vendor software, screens are provided to allow development of the AOV text and graphic report.

Table 6-7 illustrates the content of a VSAM software window that allows the entry of line performance by voltage class. Note that the number of faults per 100 miles is parsed by percentage based on fault type. For example, 20% or 2 of 10 line faults per year are due to three-phase line-to-ground faults (2LG).

Table 6-6
Effect of Transformer Connections Given a Line to Ground Fault on Phase "A" of the Primary

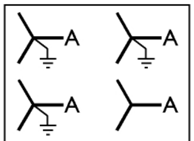
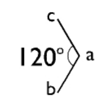
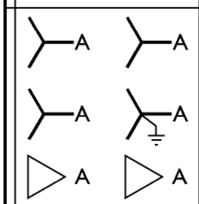
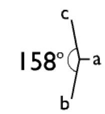
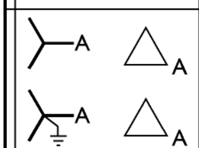
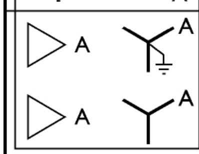
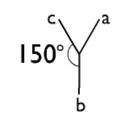
Transformer Connection	Per Unit Voltage						Phasor Diagram
	Phase-to-Phase			Phase-to-Neutral			
	V_{AB}	V_{BC}	V_{CA}	V_{AN}	V_{BN}	V_{CN}	
	0.58	1.00	0.58	0.00	1.00	1.00	
	0.58	1.00	0.58	0.33	0.88	0.88	
	0.33	0.88	0.88	-	-	-	
	0.88	0.88	0.33	0.58	1.00	0.58	

Table 6-7
VSAM Table Used to Enter Transmission Line Performance by Voltage Class

Voltage Class (kV):		13.8
Faults / 100mi Line / Year:		10
Ohms per Mile of Line:		0.7
Faults / Bus / Year:		0.05
100%	(%) 1LG:	60
	(%) 3LG:	20
	(%) 2LG:	5
	(%) L-L:	15

Additional windows are provided to input a simple distribution model and transformer connections between the transmission bus (selected as the POI) and the end-use facility. Depending on user requirements, the VSAM can analyze up to five types of voltage sags. Another data-entry requirement is the voltage-sensitivity level of the end-use facility equipment. Once all the parameters are entered, an Area of Vulnerability report may be generated, as shown in Table 6-8. The table represents the lines in the AOV that result in voltages below 0.75 pu at the Tennessee bus. The first column indicates the fault type that resulted in the per-unit voltage-sag magnitude in the "Minimum Voltage" field in the next to last column on the right. The last column shows the type of voltage sag as illustrated and explained in Figure 6-8 following the AOV report.

Table 6-8
Area of Vulnerability Text Report from VSAM

Area of Vulnerability

Fault Type	Location Type	Name 1	Voltage 1	Name 2	Voltage 2	Circuit ID	Segment	Minimum Voltage	Sag Type
3LG	BUS	TENNESSEE	132.00			1L		0.00	A
2LG	BUS	TENNESSEE	132.00			1L		0.00	D
L-L	BUS	TENNESSEE	132.00			1L		0.00	D
L-L	BUS	NEVADA	132.00			1L		0.22	D
2LG	BUS	NEVADA	132.00			1L		0.22	D
3LG	BUS	NEVADA	132.00			1L		0.23	A
L-L	BUS	TEXAS	132.00			1L		0.33	D
2LG	BUS	TEXAS	132.00			1L		0.33	D
3LG	BUS	TEXAS	132.00			1L		0.33	A
L-L	BUS	CLAYTOR	132.00			1L		0.41	D
2LG	BUS	CLAYTOR	132.00			1L		0.42	D
3LG	BUS	CLAYTOR	132.00			1L		0.42	A
L-L	BUS	GLEN LYN	132.00			1L		0.48	D
2LG	BUS	GLEN LYN	132.00			1L		0.48	D
3LG	BUS	GLEN LYN	132.00			1L		0.48	A
L-L	BUS	REUSENS	132.00			1L		0.49	D
2LG	BUS	REUSENS	132.00			1L		0.49	D
3LG	BUS	REUSENS	132.00			1L		0.50	A
L-L	BUS	ARIZONA	132.00			1L		0.58	D
2LG	BUS	ARIZONA	132.00			1L		0.59	D
3LG	BUS	ARIZONA	132.00			1L		0.59	A
1LG	BUS	TENNESSEE	132.00			1L		0.63	C
L-L	BUS	OHIO	132.00			1L		0.65	D
2LG	BUS	OHIO	132.00			1L		0.65	D
3LG	BUS	OHIO	132.00			1L		0.65	A
1LG	BUS	NEVADA	132.00			1L		0.66	C
1LG	BUS	TEXAS	132.00			1L		0.71	C
L-L	BUS	FIELDALE	132.00			1L		0.72	D
2LG	BUS	FIELDALE	132.00			1L		0.72	D
3LG	BUS	FIELDALE	132.00			1L		0.72	A
1LG	BUS	CLAYTOR	132.00			1L		0.72	C
L-L	BUS	VERMONT	33.00			1L		0.74	D
2LG	BUS	VERMONT	33.00			1L		0.75	D

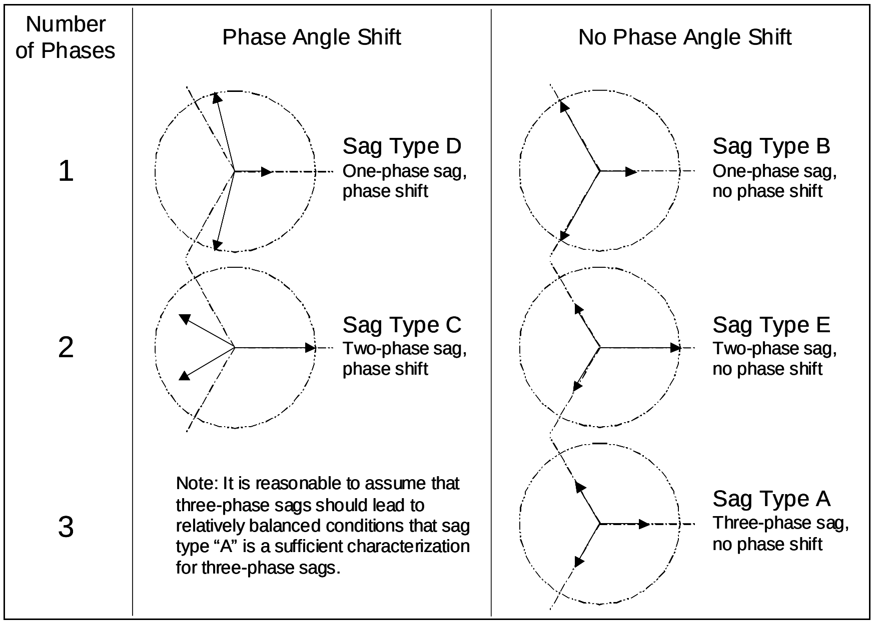


Figure 6-8
Description of Sag Types Reported by the VSAM

The annual voltage-sag profile illustrated in Figure 6-9 provides a graphic representation of the AOV results. This graph estimates the number of times end-user equipment might be affected based on the equipment sensitivity to voltage-sag magnitude and type.

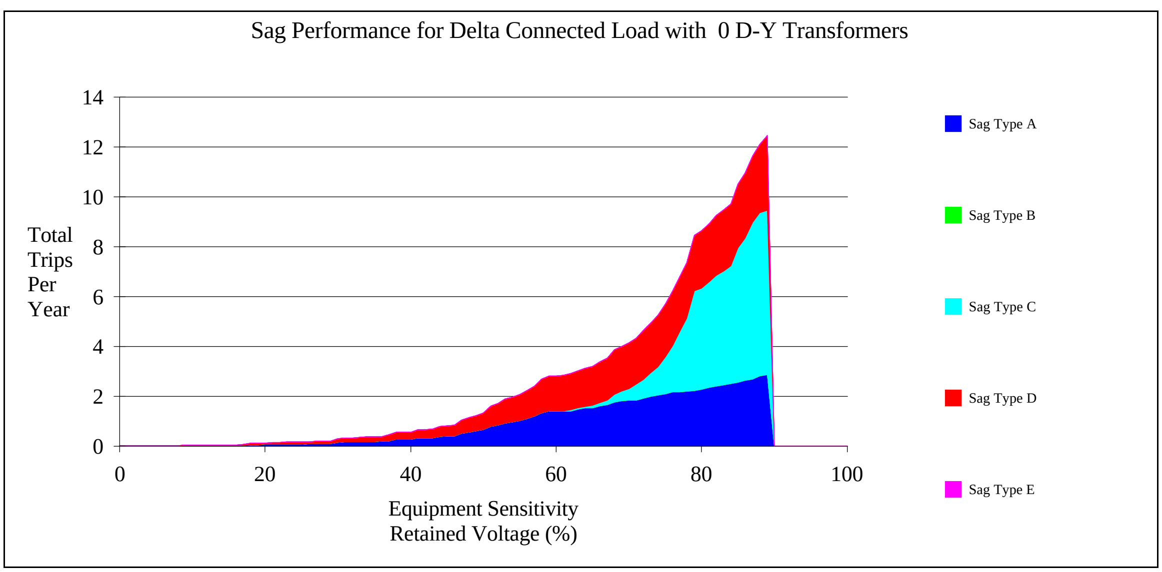


Figure 6-9
Annual Voltage-Sag Profile by Sag Type

As mentioned earlier, the VSAM is included in EPRI's PQDS software. When an AOV study is performed in the PQDS, key information as shown in Table 6-9 is passed from the VSAM to the PQDS Economic Assessment Module. The Economic Assessment Module, to support the economics of custom power and other power quality solutions, uses this data.

Table 6-9
Monthly Disturbance for Economic Analysis

Magnitude of Retained Voltages	1 and 2 Phases	3 Phases	Total
80 < V <= 90	0.28	0.05	0.33
70 < V <= 80	0.34	0.04	0.37
50 < V <= 70	0.13	0.10	0.23
10 < V <= 50	0.05	0.05	0.10
0 < V <= 10	0.00	0.00	0.00

Note that not all the reports created by the Voltage Sag Analysis Module are shown. However, enough have been shown to give the reader a sense of how the Voltage Sag Analysis Module is used with ASPEN's short-circuit program, which uses a method of fault positions.

Vendor's Area of Vulnerability Macro

Another approach to estimating transmission performance while still utilizing the fault-position approach is under development by another system-modeling vendor (CAPE software by Electrocon International, Inc.). Electrocon is working with a utility in the southeast United States to develop an Area of Vulnerability (AOV) Macro. The AOV macro runs within CAPE to accept POI location, voltage-sag sensitivity threshold of end-user equipment, fault types, and line performance data to generate an AOV report. The resulting report is provided as a text document or a graphical one-line representation of the AOV.

CAPE applies the fault-position method differently than previously discussed. To reduce computation time, instead of faulting sections of a line on an incremental basis, the AOV macro finds the exact point on the line where a fault will result in voltage sag equal to the end-user equipment sensitivity at the end-user location or POI. This exact fault point represents the border of the AOV. Once the border point is defined on a line, the distance information is applied to line-performance data to determine the frequency of faults on the system. The following provides a detailed description of the AOV macro as it was presented in a Paper at PQA 2000 [5]. The method employed for identifying buses, lines, and partial lines that represent the "Area of Vulnerability" is simple in concept and straightforward to implement with existing functions of the CAPE User's Programming Language (CUPL). The method takes advantage of the fact that the fault calculation itself is highly efficient and is not measurably affected by the size of the network under study. Computationally speaking, fault calculations are almost "free."

The underlying assumption is that the impact of a fault on the voltage at a Point of Interest (POI) decreases with increasing distance between the two. We refer to this distance with the admittedly imprecise term "bus depth," the number of real buses along the shortest path between the POI and fault location. (Real buses are those with breakers and protection, as opposed to so-called fictitious buses that may represent such locations as load taps, multi-terminal line junction points, and mutual coupling boundary points.) The CUPL RING function is used to build "test sets" of buses within successively greater bus depths outward from the POI, beginning with bus depth = 1. The user-specified types of faults are applied one at a time to each member of the initial test set. Typically, at least one bus in the initial test set leads to a POI voltage violation. Each bus that causes a POI voltage violation is added to a second set used to collect only buses in the AOV.

A loop is now entered in which a new test set is formed that encompasses the next depth level. The intersection of the new test set with the previous set is removed, and the remaining buses are checked. Any members of this "outer ring" that cause a POI violation are added to the AOV set. If at least one violation occurs, the next level test set is created, the intersection with the previous test set is found and checked, and so on until the intersection yields no AOV violation. At this stage, the set used to collect the AOV buses contains all of the buses that cause a POI violation. Furthermore, the last bus found was located on the ring of bus depth one less than the last bus checked.

The initial assumption ensures that any transmission line within the AOV must be connected to at least one bus in the AOV bus set. Those connecting two AOV buses are assumed to lead to POI violations over their entire length for at least one of the specified fault types. Those connecting only one must contain an AOV boundary. Lines needing to be checked are found by first forming a branch set obtained by applying the DOLINES looping function to each member of the AOV bus set and adding the connected lines one at a time. The full branch set is passed through once, both ends of each line are faulted, and the line is added to a second AOV branch set if one bus does not cause a violation. These are the AOV boundary lines and require further processing to find the precise boundary location.

The last core operation is to determine the AOV boundary location on each line for each type of fault. This is done by applying a given type of fault successively on the line in a so-called "golden search" while comparing the voltage at the POI with the specified threshold level. The same algorithm is used in fault locators and instantaneous over-current element reach computations. Most searches require five to eight fault applications to find a boundary to within a fraction of a percent.

The AOV macro accepts the POI location, the voltage-sag sensitivity threshold of end-user equipment, fault impedance; fault types, and line-performance data to generate an AOV output report. The resulting report is provided as a text document or a graphical one-line representation of the AOV. Figure 6-10, Figure 6-11, and Figure 6-12 illustrate the different sections of the text report. Figure 6-13 illustrates one of several graphic representations of the AOV.

Area of Vulnerability Study

Point of interest: 256 Barton 5 (Substation: BARTON SUB)
POI voltage threshold: .500
AOV Fault Type: ALL FAULT TYPES
Fault Resistance: .500 Ohms

Report of Buses in AOV

Faults At:

Substation	Bus Number	Bus Name	Minimum POI Voltage	1 L G	2 L G	3 L G	L L	Events/ Year
BARTON SUB	256	Barton 5	.0356	Y	Y	Y	Y	.050
COLBERT FOSSIL PLANT	260	Colbert 161	.2147	Y	Y	Y	Y	.050
BARTON SUB	1015	Barton Tap 5	.0690	Y	Y	Y	Y	.050
COLBERT FOSSIL PLANT	26001	Colbert 5-1	.2147	Y	Y	Y	Y	.050
COLBERT FOSSIL PLANT	26002	Colbert B2-1	.2147	Y	Y	Y	Y	.050
COLBERT FOSSIL PLANT	26003	Colb 2-2&2-3	.2147	Y	Y	Y	Y	.050
COLBERT FOSSIL PLANT	26004	Colb B1&2-1T	.2147	Y	Y	Y	Y	.050
							Total Bus Events/Year =	.350

Figure 6-10
CAPE AOV Macro Text Report with Study Parameters and Buses in AOV

Report of Lines in AOV

From: Substation	Bus Number	Bus Name	To: Substation	Bus Number	Bus Name	Ckt	Fault Type	Minimum POI Voltage	% in Violation	Events/ Year
BARTON SUB	256	Barton 5	BARTON SUB	1015	Barton Tap 5	1	1LG	.0356	100.0	.000
							2LG	.0488	100.0	.000
							3LG	.0541	100.0	.000
							L_L	.4474	100.0	.000
BARTON SUB	1015	Barton Tap 5	BAY SPRINGS, MS	1229	Bay SpringsT	1	1LG	.0690	19.76	.078
							2LG	.0860	23.20	.008
							3LG	.0939	24.35	.032
							L_L	.4474	6.74	.007

Figure 6-11
CAPE AOV Macro Report of Lines in AOV

COLBERT FOSSIL PLANT	26003	Colb 2-2&2-3	MOULTON PRIMARY SUB	1017	Moulton tap	1	1LG	.2147	3.58	.000
							2LG	.2188	5.16	.000
							3LG	.2193	6.36	.000
							L_L	.3863	2.44	.000
COLBERT FOSSIL PLANT	26003	Colb 2-2&2-3	TULU	1227	Tulu New T	1	1LG	.2147	2.87	.133
							2LG	.2188	4.04	.016
							3LG	.2193	4.68	.072
							L_L	.3863	2.10	.024

Total Line 1LG Events/Year = 1.293
Total Line 2LG Events/Year = .155
Total Line 3LG Events/Year = .734
Total Line L_L Events/Year = .224
Total Line Events/Year = 2.405
Total Bus & Line Events/Year = 2.755

Figure 6-12
CAPE AOV Macro Report of Lines in AOV with Line and Bus Summary

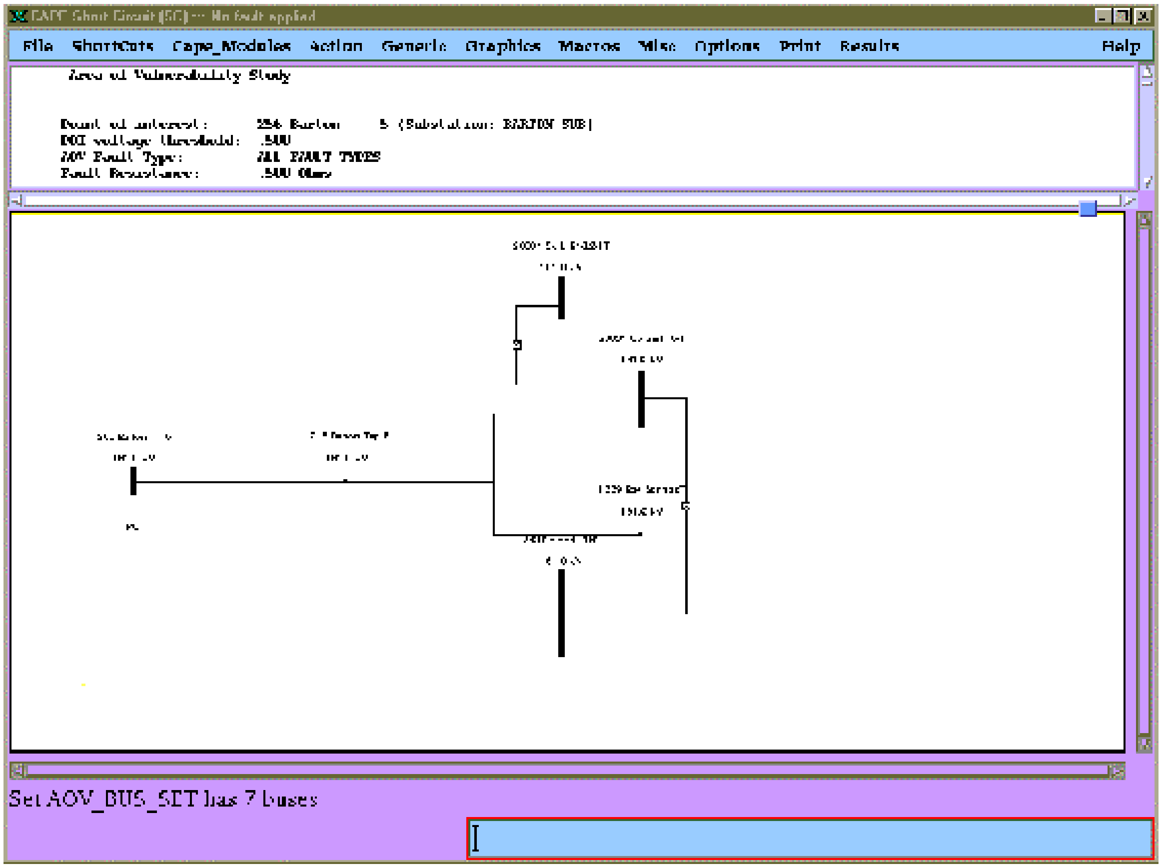


Figure 6-13
CAPE AOV Macro QuickDraw of AOV Only

References

1. Bollen, Math H.J., *Understanding Power Quality Problems: Voltage Sags and Interruptions*, Institute of Electrical and Electronics Engineers, New York, New York, 2000, pp 360.

2. EPRI, *Power Quality Workbook for Utility and Industrial Applications*, TR-105500, Final Report, October 1995, pp 3-49 through 3-54.

3. EPRI, Power Quality Toolbox: Voltage Sag Analysis Module, CD-109127, Final Report, October 1997.

4. EPRI, Integrated Power Quality Diagnostic System for PC Workstation, CD-111194, Final Version 1.0, November 1998.

5. Carl Miller, Paul McGuire, Ashok Sundaram, Michael Ingram, and Russell Patterson, "Implementation of Area of Vulnerability (AOV) Methodology in CAPE," *PQA2000,* Memphis, Tennessee, May 2000.

7 VOLTAGE-SAG ESTIMATION USING MONITORING

This chapter addresses the issues associated with monitoring power quality levels on transmission systems. Two approaches are identified: direct monitoring of the transmission system and indirect monitoring of the power quality levels on the transmission system via distribution-level monitors. The pros and cons of each method are discussed, as well as system information and characteristics that are required in order to ensure a successful monitoring project.

Direct Monitoring of Transmission System

Disturbance monitoring requires that voltage be continually sampled and recorded only if the signals exceed specified values. Line-to-ground voltages (all three phases) will typically be monitored for transmission systems. Some disturbances, such as harmonics, require that phase currents be recorded as well.

If a trigger threshold is exceeded, all channels should be recorded along with an adequate number of pre-trigger and post-event cycles. In general, the recorded data should be categorized and stored in a relational database for subsequent viewing and analysis.

Some power quality benchmarks such as voltage phase unbalance, harmonic content, noise, DC offset, system frequency variations, and voltage flicker can be derived from a periodic sampling schedule. For most of these benchmarks, sampling once per hour and capturing several cycles for each of the channels would be sufficient to establish these benchmarks. The schedule and details for voltage flicker are a special case and will be addressed later.

The recorded data from the periodically sampled benchmarks also needs to be processed and stored in a relational database. The post-processing and viewing software needs to generate the trends of these benchmarks over time and have configurable alarm values for each one.

Remote retrieval of recorded data should be available via telephone or Internet connections. The ability to remotely control and alter the configuration of the recorder should also be provided. In general, each event needs to be "time stamped" with a time-code resolution of 1 millisecond or less, reference traceable to NIST (National Institute of Standards and Technology) or the Naval Lab GPS standard. All data-collecting equipment should be able to export all of the recorded data in an "open" non-proprietary format such as PQDIF.

The technical specification requirements for the monitoring instruments will vary depending on the benchmarks being monitored, but some typical specifications for a power quality monitor are tabulated in Table 7-1 [1].

Table 7-1
Typical Specifications for a Power Quality Monitoring Instrument

Operating Voltage			
AC voltage		90 - 290 Vrms	
Frequency		45 - 65 Hz	
Power		up to 40 VA	
Measurement Range			
Voltage	RMS & waveshape	10 - 600 Vrms, (10 - 170 Vrms optional), 6 kHz, 45 - 65 Hz fundamental up to 8 kHz	
	Impulse	50 V - 6 kV peak, 4 kHz - 1 MHz	
Current	RMS & waveshape	0.01 - 10 Arms, 25 A peak, 45 Hz - 4 kHz	
Input Characteristics			
Type	Voltage	Solid state differential, DC coupled	
	Current	Transformer isolation, AC coupled	
Impedance	Voltage	1 Megohm to ground, < 50 pf to ground	
	Current	Infinite	
Dielectric		> 2.5 kV to chassis	
Connections	Voltage	Screw terminal, up to #10 AWG wire	
	Current	Tube, 3/8 inch diameter	
Accuracy			
Voltage	RMS	0.01% full scale, 0.01% of reading	
	Impulse	5% (20 - 200 V), 2% (200 V - 6 kV)	
Current	RMS	0.02% full scale, 0.01% of reading	
Environmental			
Operating temperature		-30° to 40°C (-22° to 140°F)	
Operating humidity		95% non-condensing	
Storage temperature		-40° to 75°C (-40° to 167°F)	
Storage humidity		95% non-condensing	
Shock/vibration		30 G	
Dimensions			
Width		2" (5 cm)	
Length		14" (35.5 cm)	
Depth		6" (15.2 cm)	
Battery Endurance		Standard Config.	Long Life Option
Operation		15 minutes	8 hours
Data storage		2 days	60 days
Setup storage		5 years	5 years

The requirements for both the data-collecting equipment and the corresponding analysis software vary with the type of power quality disturbance being monitored. The tabulation in Table 7-2 gives a general overview of this variation with more specifics being provided [2].

Table 7-2
Equipment Requirements for Various Types of Power Quality Disturbances

Concern	Instrument/Software Measurement and Control	Instrument/Software Analysis and Display
Harmonic Levels	• Voltage and current • Three-phase • Single-phase acceptable for balanced three-phase loads • Waveform sampling • Configurable periodicity • Synchronized sampling	• FFT capability • Trending • Waveform and spectral plots
Long-Term Voltage Variations	• Three-phase voltage • RMS sampling • Configurable periodicity	• Trending • Magnitude-versus-duration plots
Short-Term Voltage Variations, Interruptions	• Three-phase voltage • RMS sampling • Configurable threshold level • One-cycle RMS resolution	• Magnitude-versus-duration plots
Low-Frequency Transients	• Three-phase voltage and current • Waveform sampling • Frequency response @ 5 kHz • Configurable threshold level	• Waveform plots showing pre-event and recovery
High-Frequency Transients	• Three-phase voltage & current • Frequency response @ 1 MHz • Impulse peak and width detection • Configurable threshold level	• Waveform plots showing position of impulse on power frequency sinusoid

RMS Voltage Variations

The occurrence of RMS voltage variations on the transmission system are going to be random in nature and therefore need to be collected over time in order to have enough samples or operating experience to predict future performance based on the collected historical data. It has been estimated that one year's worth of data would give accuracies of plus-or-minus 50%. The accuracy improves as the number of years of data increases.

Data on RMS voltage variation should consist of true RMS waveforms for each of the three phases for each RMS voltage variation. Monitoring equipment capable of recording a true RMS voltage variation should have configurable trigger thresholds that will determine what events are recorded. The trigger points would typically be set to coincide with the definition of a sag ($V_{RMS} <$ 0.9 pu for 0.5 cycles) and a swell ($V_{RMS} >$ 1.10 pu for 0.5 cycles). Ideally, the recorder will also record a few cycles of “pre-trigger” data and continue recording a few cycles after the event is over. The pre-trigger and post-event data would ideally be the digitized version of the actual waveforms to help identify the cause of the excursion, but only the true RMS values would typically be stored over the full duration of the event. The recorder should have a one-cycle RMS resolution.

RMS values for overvoltages and undervoltages should be computed once per cycle. Initially, all values should be stored, but if the event has not ended after a user-definable time period, the instrument should switch to averaging several cycles of RMS data in order to conserve memory. At this point, the RMS plot should diverge from a single-valued line to a band of average, minimum, and maximum values. During extremely long events, the instrument should switch to successively longer averaging periods.

It is important that the monitoring equipment records “true RMS” values in case the waveforms have some distortion in them. True RMS converters based on a digital approach sample the input signals at approximately 100 times the anticipated signal frequency and convert the samples to digital values. A mathematical processor squares each of the values, sums the squares along with some previously squared samples, and then calculates the square root of the sum. This technique will yield a true RMS value on any arbitrary waveform.

The processed data should be stored in a satisfactory relational database, which can be accessed for selected post-processing and analysis. During data storage, it is also desirable to store a characterization of the RMS voltage variation in terms of both a magnitude and duration. Characterization during data storage allows for a rapid report generation for the end user.

The post-processing capabilities of the analysis software should allow for viewing and comparing the recorded RMS variations against established industry standard benchmarks such as the ITIC and SEMI 2844 curves. It should also allow for comparison against any specified voltage/time characteristic that may represent a specific equipment capability or future industry standards.

The software also needs to be able to calculate the standard industry indices that are used to characterize voltage-sag performance. The most basic of these indices is the System Average RMS (Variation) Frequency Index Voltage (SARFIx):

$$\mathrm{SARFI}_x = \frac{\sum N_i}{N_T} \qquad \textbf{(7-1)}$$

where:

- $X \equiv$ RMS voltage threshold; 7
  possible values - 140, 120, 110, 90, 80, 70, 50, and 10.
- $N_i \equiv$ number of customers experiencing voltage deviations with magnitudes above X % for $X > 100$ or below X % for $X < 100$ due to measurement event *i.*
- $N_T \equiv$ number of customers served from the section of the system to be assessed.

The post-processing software should also allow for variable temporal and phase aggregation of RMS variations.

Statistics on Transmission-Line Interruptions

Ideally, the following data would be available for every unscheduled transmission-line breaker operation that was associated with a fault:

- Physical location of the fault.
- Number of phases involved.
- Fault impedance.
- Fault duration.
- Time stamp for correlation with any power quality monitoring data.

If the above-mentioned data were available for every unscheduled transmission-line breaker operation that was associated with a fault, then it would be possible to very accurately calculate the resulting RMS voltage-variation profile at any point within the electrical model of the transmission system. Unfortunately, the details and accuracy of such data are not always readily available. However, by using a combination of calculation techniques and assumptions, it is possible to achieve reasonable estimates of RMS voltage profiles even with a limited subset of the above mentioned data. The two most important sources for obtaining data on transmission-line interruptions are the breaker operation logs and digital fault recorders.

Breaker operation logs may automatically be generated by sequence-of-events (SOE) recorders, manual recording by operators, or a combination of the two. As a minimum, the breaker operation log should identify the circuit involved, a time stamp associated with the beginning of the interruption, the duration of the interruption, and the cause. This information is sufficient for the identification of all unscheduled breaker operations that are associated with faults.

The physical location of the fault is narrowed down to somewhere on the circuit that has opened. The cause may help to identify the exact location if terminal equipment is involved. A breaker operation followed by a successful re-close would suggest that the location of the fault could be anywhere along the line.

The time stamp would allow correlation with any available power quality monitoring data. The resolution of the time code should be less than or equal to 1 millisecond, reference traceable to NIST or the Naval Lab GPS standard.

Computer simulations can be run to identify the most likely fault location, fault impedance, and number of phases involved. The algorithm would assume different fault locations, impedances, and phases involved until a strong correlation exists between the calculated voltage profiles and those recorded by the existing power quality meters or digital fault recorders (if available). A similar approach can also be followed using the fault current information from digital fault recorders to either supplement the recorded voltage profiles or as stand-alone information.

An alternative approach that does not require correlation with either power quality meters or digital fault recorders is to calculate and report a voltage-sag profile range rather than one finite value. The range could be evaluated by assuming different fault locations, fault types, and impedances. Even though a range is being reported, it may be quite narrow, particularly for those cases where the profile being calculated is electrically remote from the faulted transmission line.

Collected data on transmission-line interruptions should be stored in a relational database for easy retrieval and correlation.

Voltage Transients

The configurable level of the impulse trigger should result in all channels being recorded at their standard sample rate (at least 100 samples per cycle), and the impulse characteristic should also be captured. The positive and negative peak magnitude and volt-seconds for transients of 1 to 200 microseconds should be recorded. Several cycles of pre-trigger and post-event information should also be recorded for each voltage transient.

The recorded data should be stored in a relational database, which can be accessed for selected post-processing and analysis. The post-processing capabilities of the analysis software should allow for viewing the waveform plots. These plots should show the position of the impulse on the power frequency sinusoid. It should also allow for statistical summary reports to be generated with configurable filters for both magnitude and duration.

The configurable low-frequency trigger should also result in all channels being recorded at their standard sample rate (at least 100 samples per cycle). These types of disturbances are usually captured and classified as waveform faults and are triggered by deviations from the previous cycle. A few cycles of pre-trigger and post-event should also be recorded.

Voltage Unbalance

The voltage unbalance benchmark would typically be obtained from periodic sampling. It is necessary to obtain the true RMS values for each of the three phases and then calculate the percent unbalance. The calculation routine should be able to report negative-sequence unbalance (V_2 / V_1) expressed as a percent as well as the common percent unbalance defined as:

Percent Unbalance = Abs((MaxDev RMS - Average RMS) / Average RMS) * 100%

Where MaxDev is either the maximum or minimum of the three voltage magnitudes.

The post-processing software should have a configurable warning flag triggered on excessive values (typically 1 or 2 percent).

System Frequency Variations

System frequency variations of the fundamental component are small, with typical values ranging between 0.01 Hz and 0.05 Hz. The monitor would typically need 5 significant digits of precision and be stable to +/- 0.001 Hz. The algorithm that calculates the frequency needs to be insensitive to harmonic content.

Flicker

The flicker benchmark should be derived in accordance with the international standard IEC 61000-4-15. The standard defines a transfer function that translates the measured voltage signal into two statistical indices P_{st} and P_{lt}. The voltages are continuously monitored for a time period of approximately one week. A single P_{st} (short-term) value is calculated every 10 minutes and the long-term index (P_{lt}) is a combination of 12 short-term values. Practical flicker limits are typically developed from 95^{th} and 99^{th} percentiles of this series of values [3].

Waveform Distortion

The waveform distortion benchmarks would typically be obtained from periodic sampling. Typical requirements for the collection of harmonic data would include:

- Simultaneous measurement of voltage and current so that harmonic power flow can be obtained.
- Sampling of the waveform synchronized to the fundamental frequency, to ensure accurate calculation of harmonic phase angles.
- A sampling rate sufficient to determine up to the 50th harmonic or better.
- High-resolution analog-to-digital conversion. This is necessary because high-order voltage and current harmonics are typically several orders of magnitude less than the full-scale reading of the instrument.

The post-processing software should be able to characterize the harmonic distortion levels by the complete harmonic spectrum with magnitudes and phase angles. It should also be able to calculate the total harmonic distortion (THD) for the voltage signal. If current signals are recorded, it should also calculate the total demand distortion (TDD) for the current signals.

The pre-existing monitoring equipment on the transmission system can make a very important contribution to transmission benchmarking. Transmission reliability councils have “disturbance monitoring” requirements for their members, which generally consists of digital fault recorders. These devices tend to be more popular on EHV or new substations, generating stations, and those substations deemed critical to the interconnected system.

Even for those cases where it is determined that additional monitoring equipment is required, the instrument transformers (potential and/or current transformers) will probably already be available. The availability of the existing instrument transformers is an important consideration from an overall economic point of view.

Probably the biggest challenge associated with utilizing the existing equipment is getting all of the information synchronized to a common time base and getting it in a common database format. Some transmission reliability councils are requiring all new recorders to have a time-code resolution less than or equal to 1 millisecond, reference traceable to NIST or the Naval Lab GPS standard. They are also requiring the data to be submitted and made available in the ANSI/IEEE Std. C37.111-1991, known as COMTRADE, or other universal data format.

Instrument Transformers

Instrument transformers at the transmission-voltage level are expensive devices, so every effort should be made to use any existing devices. When using an existing instrument transformer, it should be verified that any additional burden imposed on the instrument transformers does not exceed its capability or compromise its accuracy. In most cases, the additional burden associated with the recording instrument should not be a problem.

The quality and design of the existing instrument transformer will vary depending upon its original purpose (relaying, general metering, or revenue metering), and not all will be suitable for the more sophisticated power quality monitoring activities. For example, inductive voltage/potential transformers have been shown to have a relatively small error when measuring harmonics up to the 29^{th} harmonics, while some capacitive voltage transformers can exhibit large errors at a few hundred hertz. Fortunately, many of the important benchmark parameters (RMS voltage variations, interruption statistics, voltage phase unbalance, system frequency variations, and flicker) can usually be accomplished with either device.

Sequence-of-Events Recorders (SOE)

Sequence-of-event recorders are particularly useful for collecting data on transmission-line interruptions. They can be set to monitor and record the operation time of both relays and circuit breakers. The inherent capability of an SOE is now being built into digital fault recorders. Therefore, standalone SOEs will probably become less common.

Voltage Recorders

Power providers may use a variety of voltage recorders to monitor steady-state voltage variations on transmission systems. Some sophisticated models are fully capable of characterizing momentary voltage sags and even harmonic distortion levels. Typically, the voltage recorder provides a trend that gives the minimum, average, and maximum voltage within specified sampling window (for example, 2 seconds). With this type of sampling, the recorder can adequately characterize the magnitude of a voltage sag. However, it will not provide the duration with a resolution less than two seconds.

Digital Fault Recorders (DFR)

DFRs may already be in place at many substations. DFR manufacturers do not design the devices specifically for power quality monitoring. However, a DFR will typically trigger on fault events and record the voltage and current waveforms that characterize the event. This makes them valuable for characterizing RMS disturbances, such as voltage sags, during power system faults. DFRs also offer periodic waveform capture for calculating harmonic distortion levels. One of the transmission reliability councils has established the following minimum technical requirements for digital fault recorders [4]:

- Time-code resolution less than or equal to 1 millisecond, reference traceable to NIST or the Naval Lab GPS standard.
- Remote retrieval of recorded data.
- A minimum of three cycles of pre-fault and three cycles of post-fault information.
- Sufficient voltage traces to determine the three phase-to-neutral voltages. If the station bus could be split into separate sections by relay action, voltages for each of the resulting sections are desirable.
- Sufficient current traces to determine the three phase currents and the residual or neutral currents of each line, transformer, and generator.
- Breaker position status (breaker auxiliary contact, unless breaker position can be determined unambiguously by the currents and voltages recorded.).

Events shall be triggered by any of the following:

- Zero-sequence current (tertiary or residual).
- Under/overvoltage (three-phase).
- Trip buses or breaker contact operation.
- Other useful start events as desired.
- The council also identified the following characteristics as useful, but not required:
- Transmit and receive indication for the pilot-protection scheme for each pilot channel, if available.
- Polarizing currents or voltages, if available.

- Trip bus currents, if available.
- Sequence of events indicating the operation of protective schemes.

Power Quality Monitors

Special-purpose power quality monitors may also be in place at some substations. They are specifically designed to measure the full range of power quality variations. This type of instrument could typically monitor all three phases of voltage and current plus the neutral. Sampling rates of 256 points per cycle (PPC) for voltage and 128 PPC for current are common. The high sampling rates allow detection of voltage harmonics as high as the 100th and current harmonics as high as the 50th. Most power quality instruments can record both triggered and sampled data. Triggering should be based upon RMS thresholds for RMS variations and on waveforms for transient variations. Simultaneous voltage and current monitoring with triggering of all channels during a disturbance is an important capability for these instruments.

Transducer Requirements for Transmission-Level Monitoring

This section describes the transducer requirements associated with transmission power quality monitoring. The transmission voltage and current signals are the two fundamental parameters that need to be put through a transducer so that the signals can be recorded and analyzed. The most common parameter that will be recorded in conjunction with a transmission power quality project will be the voltage signal because the majority of power quality issues are defined in terms of the voltage.

The most basic type of transducer is a simple scaling-factor transducer that will be discussed in this chapter. Ideally, these scaling-factor transducers would reduce the magnitude of either the voltage or current signals by a known constant without introducing any other distortion into the signal, and they would do this for the entire spectrum (both magnitude and frequency) of the input signal range.

There are other more “sophisticated” types of transducers that essentially have a “calculation engine” built into them. For instance, they can monitor an AC voltage signal and produce a DC voltage whose magnitude is proportional to either the RMS value or the frequency of that AC signal. In general, these types of transducers are not suitable for power quality monitoring because they greatly reduce the amount of information that is available for analysis.

Some of the more important characteristics associated with transmission power quality scaling-factor transducers are [5]:

- **Signal levels**. This is not a transducer characteristic per se but rather it is a very important relationship characteristic between the transducer and the recording equipment. Signal levels should use the full scale of the instrument without distorting or clipping the desired signal.
- **Accuracy Classification**. Industry standards define different accuracy classes, which have different allowable values for maximum magnitude and phase shift errors along with other characteristic limits related to accuracy and distortion.
- **Frequency response**. This is particularly important for monitoring transients and harmonic distortion, where high-frequency signals are particularly important.

The significance of these characteristics will vary depending on the objective of the monitoring purpose. For some purposes, such as benchmarking, the most important characteristic of the voltage will be its steady-state RMS magnitude. Therefore, the frequency-response characteristic of the transducer is not as critical as perhaps issues involving magnitude accuracy. For problem-solving purposes, it is often required to record both voltage and current waveforms, and the frequency response of the transducer is therefore very important.

Transmission-level power quality monitoring with benchmarking as an objective will always require a voltage transducer in order to reduce the transmission line voltage to a value that can be safely handled by the recording equipment. In most cases, this transducer will actually be a potential transformer (PT) or Coupling-Capacitor Voltage Transformer (CCVT) that is already present for either metering or relaying purposes. The term PT as used here refers to a standard inductive type of voltage transformer. Most PTs and CCVTs are designed to provide 120 V at the secondary terminals when nameplate-rated voltage is applied to the primary. In some cases, it may be necessary to put another voltage transducer in series with the existing PT or CCVT in order to have appropriate signal levels into the recording equipment. As a general rule, the signal that is input to the instrument should never be so small that the noise level of the analog-to-digital board adversely affects it.

Standard accuracy classifications for voltage transformers range from 0.3 to 1.2, representing correction factors to obtain a true ratio. These accuracy classifications are based on the stated “volt amp” burden of the voltage transformer not being exceeded and input voltage range of 0 to 110% of nameplate voltage. Calibration tests over the intended voltage and frequency range can be used to establish ratio-correction curves in order minimize the inaccuracies associated with the voltage transformer on the overall system (transducer + meter) accuracy.

The frequency response of a standard metering class PT depends on the type and burden. In general, the burden should be a very high impedance (1 Megohm or greater). This is generally not a problem with most monitoring equipment available today. With a high-impedance burden, the response is usually adequate to at least 5 kHz, as illustrated in Figure 7-1.

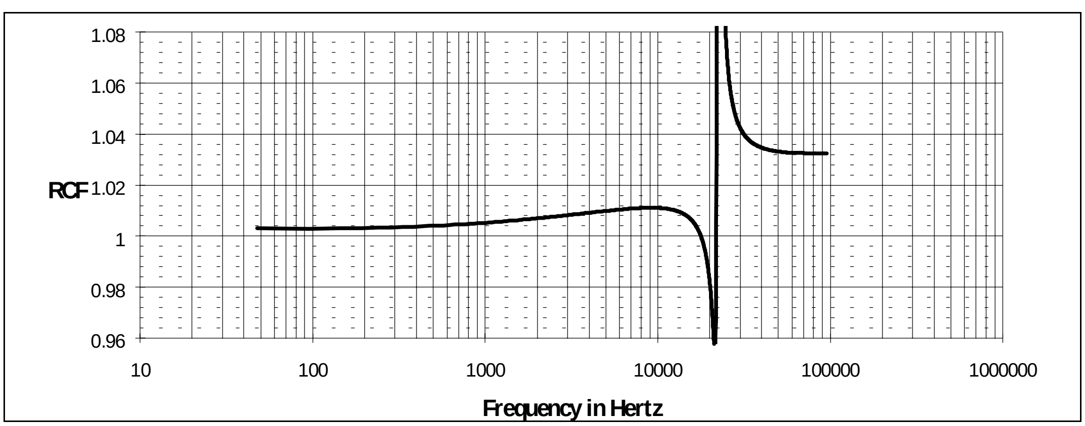


Figure 7-1
Frequency Response of a Standard PT with a One-Megohm Burden [5]

In general, CCVTs should not be used to capture harmonic or transient data. This is because the basic design (low-voltage transformer in parallel with the lower capacitor in the capacitor divider) results in a circuit that is tuned to the fundamental frequency, and the device can exhibit large errors even at a few hundred hertz. These devices could, however, be appropriate to collect data on RMS voltage variations or transmission-line interruptions. It should be noted that there are special-purpose capacitor voltage dividers that can also be used to capture high-frequency components.

Standard metering class CTs are generally adequate for frequencies up to 2 kHz (phase error may start to become significant before this). For higher frequencies, window-type CTs with a high turns ratio should be used (see Figure 7-2).

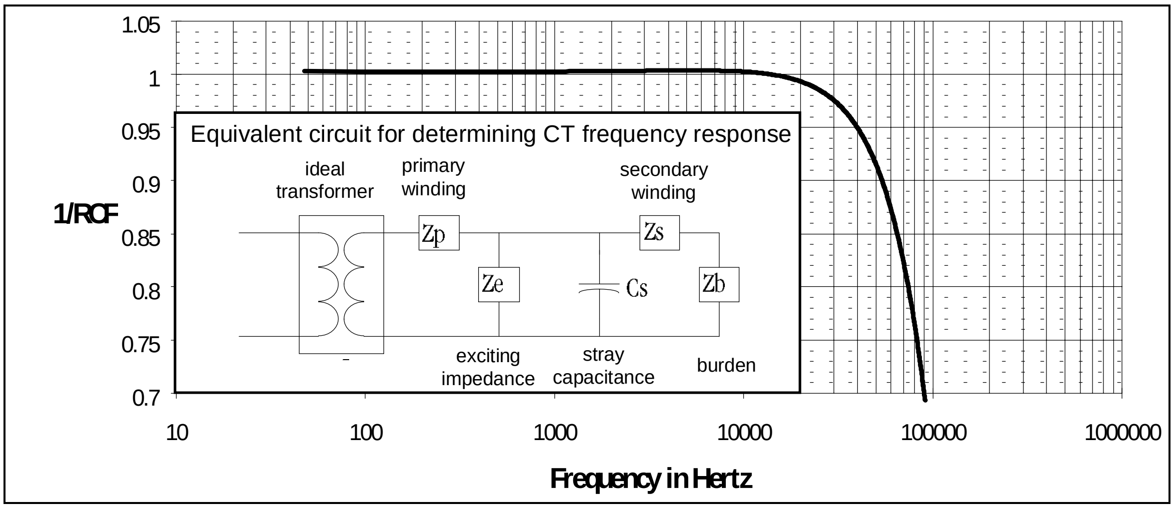


Figure 7-2
Frequency Response of a Window-Type CT [5]

Additional desirable attributes for CTs include:

- Large turns ratio, such as 2000:5 or greater.
- Widow-type CTs are preferred. Primary wound CTs (those in which system current flows through a winding) may be used, provided that the number of turns is less than five.
- Small remnant flux (such as <= 10% of the core saturation value).
- Large core area. The more steel that is used in the core, the better the frequency response of the CT.
- Resistance and leakage impedance of the secondary winding as small as possible.

Important System Characteristics for Transmission-Level Monitoring

This section describes the important characteristics of transmission systems that should be maintained and evaluated with respect to the transmission-level power quality performance. An insight into what characteristics are important to be maintained can be obtained by first reviewing the causes of unscheduled outages. The following is the list of possible causes as determined by one of the transmission regional councils [6].

Causes of Unscheduled Outages

Ten years' worth of historical data suggest that lightning accounts for about 40% of the unscheduled EHV transmission-line outages in the ECAR (East Central Area Reliability) system. Lightning activity therefore becomes a very important characteristic associated with transmission-level power quality monitoring. The following list gives insight into what else can cause faults on transmission lines and hence what can cause RMS voltage variations:

- Lightning
- Wind
- Ice or snow
- Flood
- Fire
- Galloping conductor
- Line equipment
- Contamination
- Vehicle
- Crane
- Antenna
- Airplane
- Tree Animal
- Vandalism
- Personnel error
- Undesired relay operation
- Overload
- Switching surge
- Customer-owned equipment

Lightning activity is ideally measured in terms of the number of lightning flashes per unit area per year, called the ground flash density (GFD). This value is in units of flashes per square kilometer per year or flashes per square mile per year. This value can vary greatly from region to region. Areas in Florida routinely exceed 20 flashes per square mile per year, while areas in California are routinely less than 0.1 flashes per square mile per year.

There are several characteristics of line design that can greatly influence the ability of a lightning strike to cause a flashover on a transmission line. Some of the more prominent ones are:

- Nominal voltage level
- Existence and placement of shield wires
- Resistance of tower footing

In addition to identifying characteristics that can influence faults, it is also important to identify any characteristic that may influence any of the other power quality benchmarks. The presence of shunt capacitors and the corresponding voltage-control techniques (if any) can influence the magnitude of switching events. Also important is the identification of any large customers that are fed directly from the transmission system that may have particularly disturbing loads such as arc furnaces.

Table 7-3 is a basic list of important system characteristics that should be maintained and evaluated with respect to the power quality performance of the transmission system. This list should be viewed as a baseline list with the flexibility to add other important characteristics on an as-needed basis.

Table 7-3
Important System Characteristics for Transmission Power Quality Monitoring

Nominal voltage Level
Ground flash density (flashes per square mile per year)
Typical tower footing resistance
Shield wire description
Transformer grounding practices (solid, resistive, inductive)
Voltage-control techniques (shunt capacitors/inductors and/or any related transient-suppressing techniques)
Terrain/environment description (susceptibility to fire, wind, ice, contamination, airplanes, animals, vegetation)
Typical fault-clearing times
Special customer description (arc furnaces or other large waveform-distorting loads)
Special design factors (non-standard BIL insulators/equipment, transmission-line lightning arresters, counterpoise)

Monitoring of Distribution System

As mentioned in the previous section, direct monitoring of the transmission system is the preferred approach to benchmarking power quality levels on the transmission system. There are several obstacles to performing transmission-level power quality monitoring: cost, accessibility of the monitoring point, installation concerns, and so on. For these reasons, a method of monitoring distribution-level events and correlating them to transmission-level events is explored.

With the availability of distribution-level power quality monitors currently installed on distribution systems nationwide, it would be beneficial, both from an economic and engineering standpoint, to incorporate these monitors into a transmission-level benchmarking project. In order to use distribution-level power quality monitors in this manner, the appropriate techniques and algorithms need to be developed that distinguish between transmission-level events and distribution-level events captured by distribution-level power quality monitors. This section investigates concerns associated with these techniques and algorithms.

Upstream Versus Downstream Events

Through the use of simulations, techniques are explored in an effort to evaluate the effectiveness of using distribution-level power quality monitors for benchmarking transmission systems. The simulations use the 115 kV, normal energization case from the *EPRI Power Quality Diagnostic System, Capacitor Switching Simulator, version 1.0.* The one-line diagram for the system is shown in Figure 7-3. For all the simulations preformed in this section, all capacitors were taken out of service.

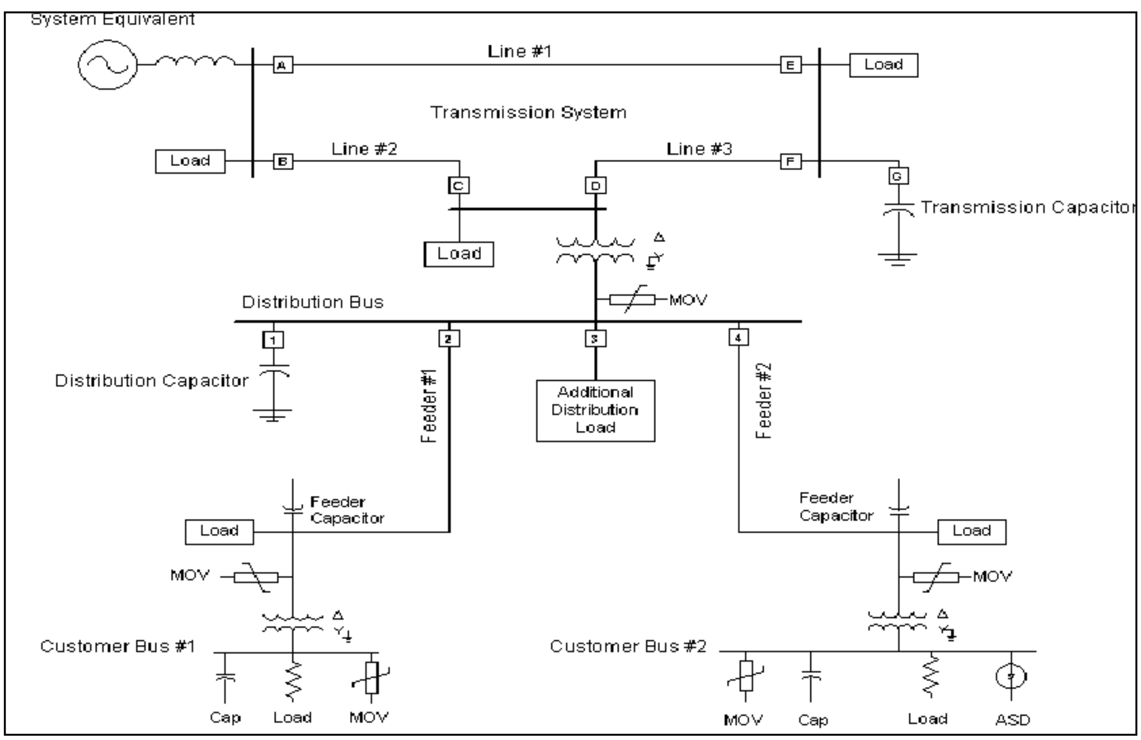


Figure 7-3
One-Line Diagram of System Under Consideration

Determining the fault location (distribution level or transmission level) is critical for benchmarking the power quality performance of the transmission system. The case listed in Table 7-4 is used to verify that the actual location of the fault can be determined through the use of distribution-level power quality monitors. For the cases listed, it is desired to determine the location of a fault. This determination is to be made from measuring current only. As will become clear, the point at which monitoring must take place is key to making a successful determination.

Table 7-4
Case List for Upstream versus Downstream Simulations

Case	Fault Location	Measurement Location
1	115-kV Substation 2	Distribution Feeder 1, Current Only
2	Distribution-Level Feeder 2	Distribution Feeder 1, Current Only
3	Distribution-Level Feeder 1	Distribution Feeder 1, Current Only
4	115-kV Substation 2	Entire Distribution Bus Current
5	Distribution-Level Feeder 2	Entire Distribution Bus Current
6	Distribution-Level Feeder 1	Entire Distribution Bus Current

For the first three cases, the monitor is placed at the distribution level. The monitor was monitoring the current in Feeder 1 only. Faults were placed on the transmission system, distribution feeder 2, and distribution feeder 1, respectively.

Case 1: Fault Occurs on the 115-kV Transmission System at Substation 2

For case one, a three-phase fault was placed on the bus of Transmission Substation 2. The fault was cleared within 5 cycles. The fault location is denoted by an “**X,**” and the monitoring point (Feeder 1 breaker) is shown by an “M” inside a box with an arrow. This is illustrated in Figure 7-4.

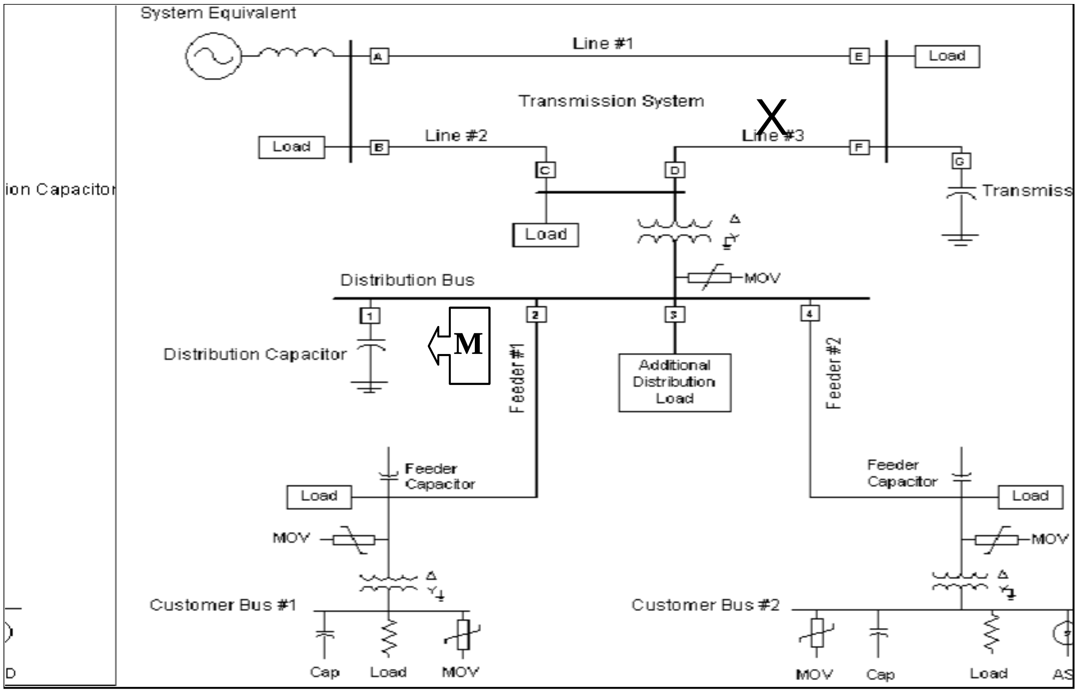


Figure 7-4
Case 1 Fault Location and Monitoring Location

The results of the simulation are illustrated in Figure 7-5. The measured feeder current decreases during the fault, which indicates that the fault was not downstream of the monitoring point at Feeder 1 breaker. Had the fault been downstream of the monitor, fault current would have been measured flowing to the point of the fault. This is not to say that the fault did not occur on a parallel distribution feeder from the same substation. A fault on Feeder 2 would have caused a voltage sag on the distribution system, but the monitor would not have seen any significant fault current.

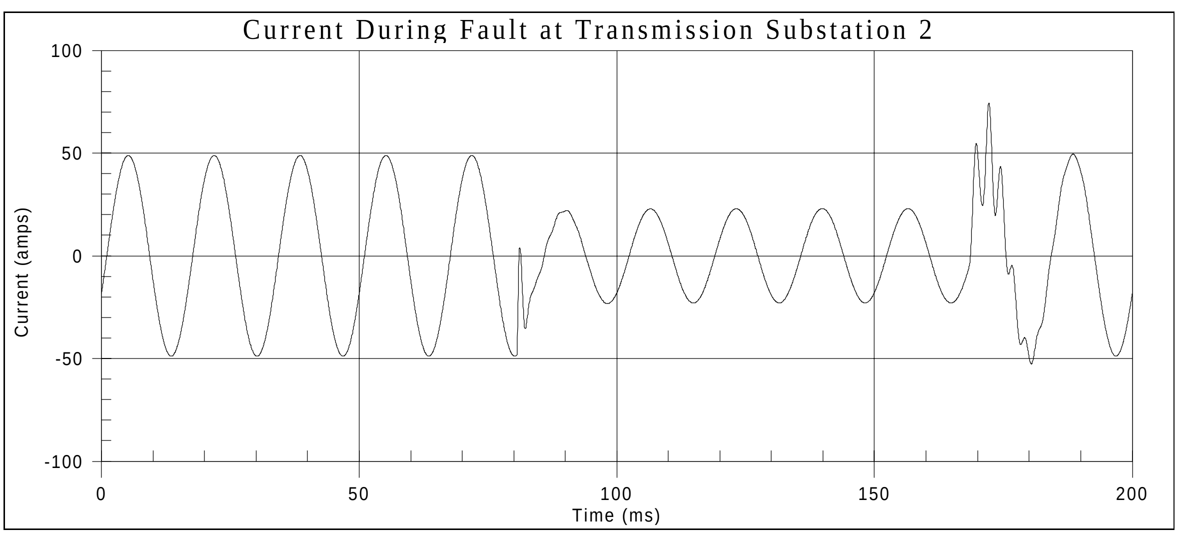


Figure 7-5
Results of Simulation Case 1

Case 2: Fault Occurs on Distribution Feeder 2

For Case 2, a three-phase fault was placed on the high side of the transformer supplying Customer Bus #2. The fault was cleared in 5 cycles. Typically, distribution-level faults are cleared in approximately 12 cycles; however, the duration of the fault is immaterial to the point being made. The power quality monitor remained at feeder 1. Figure 7-6 illustrates the circuit configuration for Case 2. The results for Case 2 are shown in Figure 7-7.

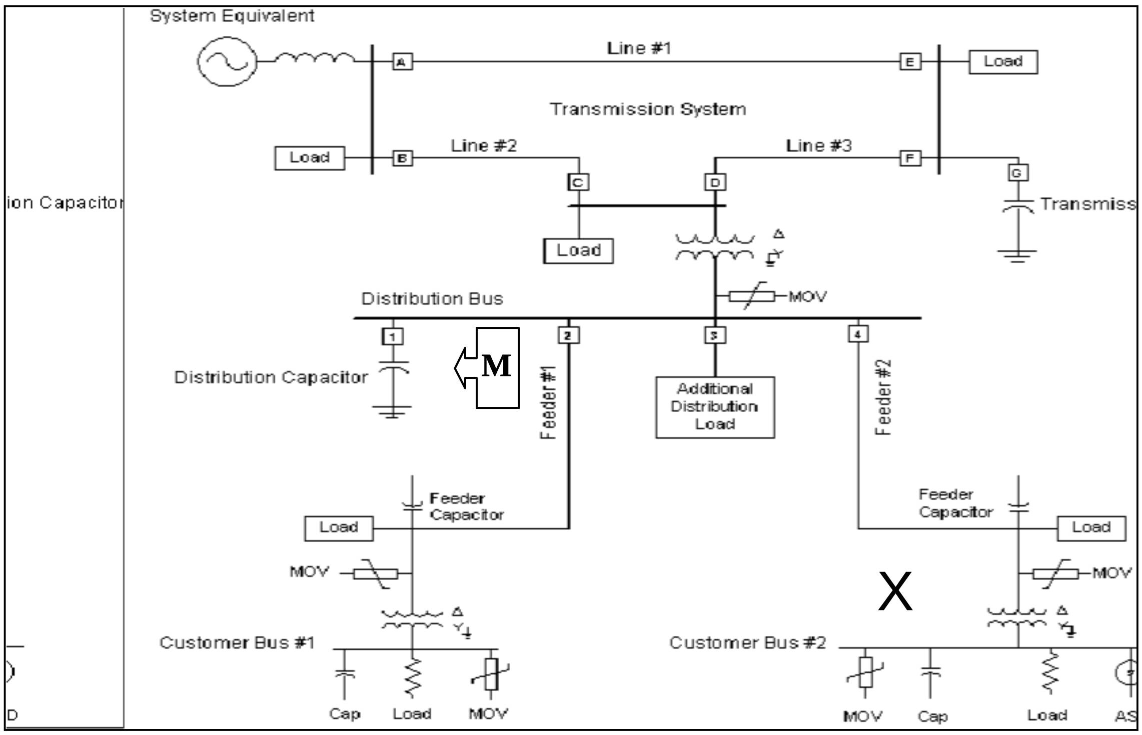


Figure 7-6
Fault at End of Feeder 2 and Monitoring Location at Feeder 1 Breaker

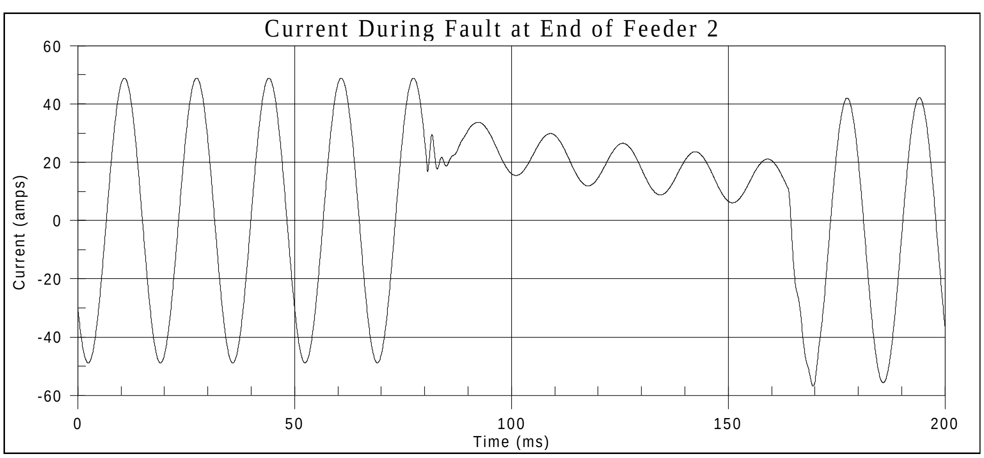


Figure 7-7
Fault on Feeder 2, Monitored at Feeder 1 Breaker

Case 3: Fault Occurs on Distribution Feeder 1

For Case 3, a three-phase fault was placed on the high side of the transformer supplying Customer Bus #1. The fault was cleared in 5 cycles. The power quality monitor remained at feeder 1. Figure 7-8 illustrates the circuit configuration for Case 3.

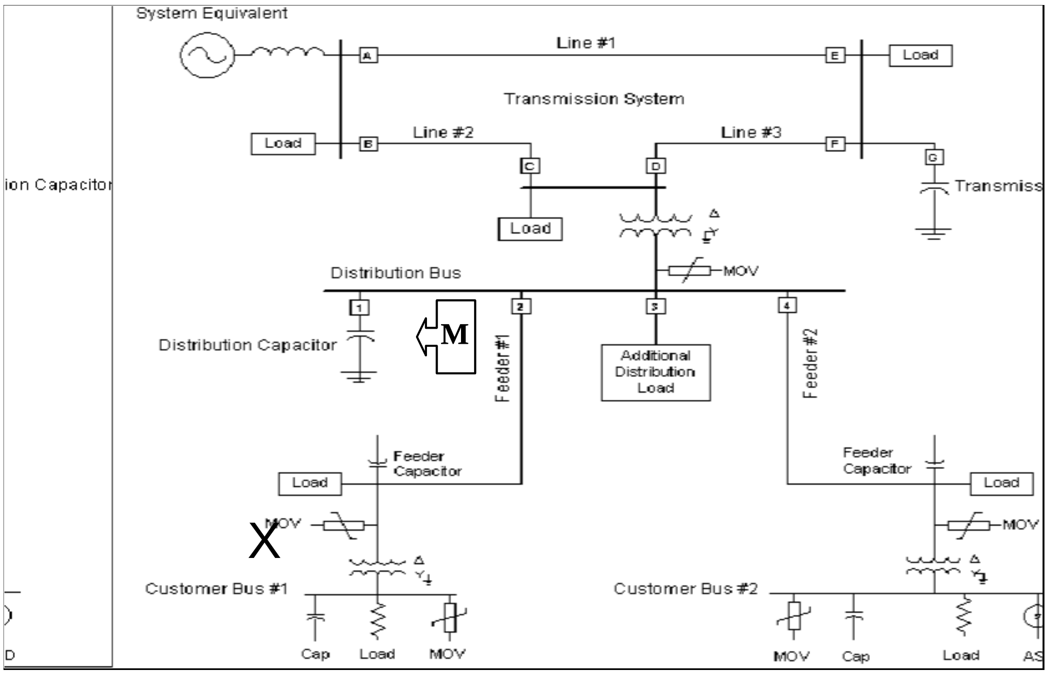


Figure 7-8
Fault at End of Feeder 1 and Monitoring Location at Feeder 1 Breaker

The results for Case 3 are shown in Figure 7-9. Notice the increase in current due to the fault location relative to the monitoring location.

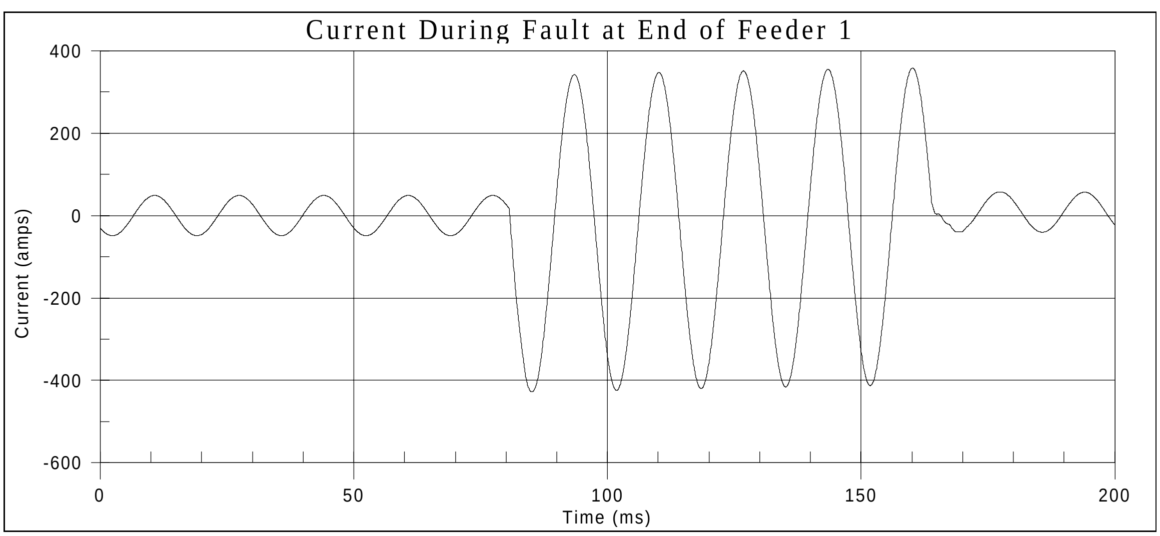


Figure 7-9
Fault on Feeder 1, Monitored at Feeder 1 Breaker

Discussion of Results of Case 1, Case 2, and Case 3

Monitoring at a distribution feeder breaker showed clear differences between a fault downstream of the meter and faults that were not downstream. The obvious difference is the flow of fault current through the Feeder 1 breaker (Figure 7-9). For the two faults that were not downstream of the meter, one was a transmission fault (Figure 7-5) and the other was a fault on a parallel distribution feeder (Figure 7-7). No fault current was observed.

The recorded waveforms from the transmission fault and the fault on the parallel feeder look very much the same and have much the same characteristics. It is not possible to differentiate between a fault on a parallel feeder and an upstream transmission fault by monitoring at the feeder level on the distribution system. An educated guess can be made as to the location of the fault, but this guess would require knowledge of the fault impedance, relay operation times, and other information.

It is speculated that by placing current transformers (CTs) or using existing CTs to measure the entire distribution bus current, upstream faults (transmission and substation transformer) can be clearly differentiated from downstream faults on the distribution system. This theory is investigated in the next section.

Extrapolation of Distribution-Level Monitoring of Voltage Sags to Transmission Level

The previous section investigated the possibility of differentiating between downstream events and upstream events at a given monitoring location. The results of that investigation proved that for certain cases and system configurations, it is possible to distinguish between upstream events and downstream events.

The following three cases were used to evaluate the benefits of measuring the entire distribution bus currents in relation to determining fault direction. The following three cases place faults on the system at the same points as the previous three cases. The only difference is the location of the power quality monitor. For these three cases, the power quality monitor was configured to measure the entire bus current of the distribution-level transformer, as illustrated in Figure 7-10.

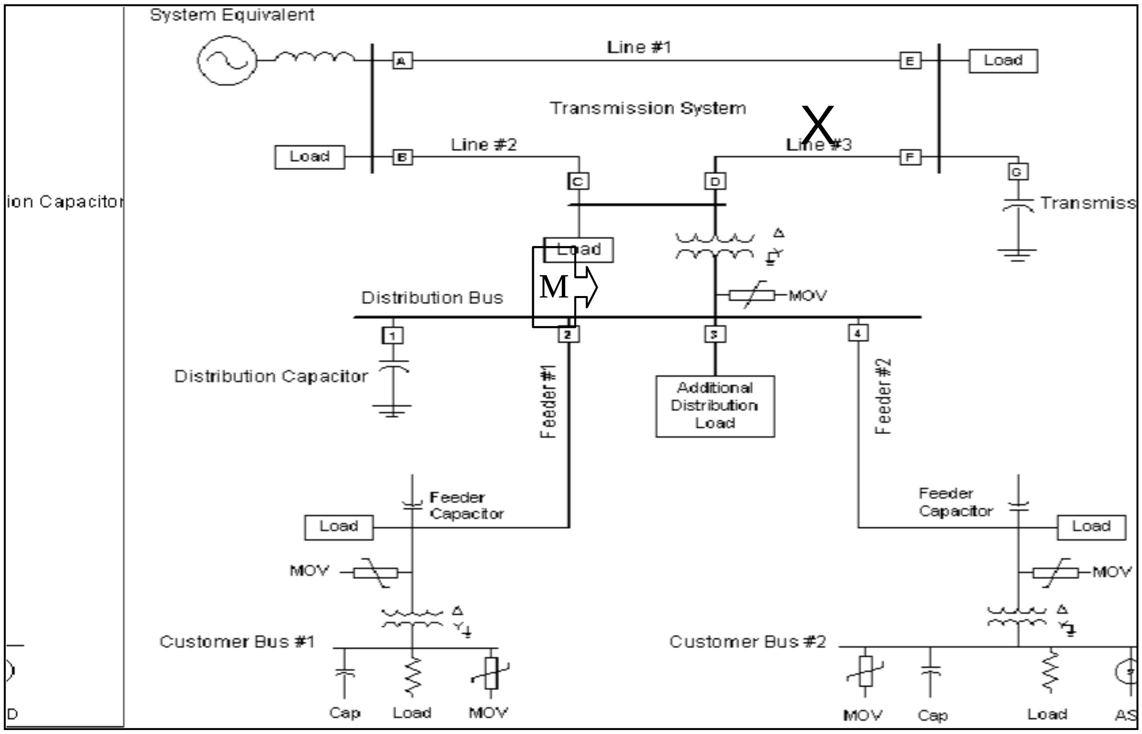


Figure 7-10
Monitoring Location at Secondary of Distribution Transformer

Case 4: Fault Occurs on the 115-kV Transmission System at Substation 2

For Case 4, a three-phase fault was placed on the bus of transmission substation 2. The fault was cleared within 5 cycles. As seen in Figure 7-11, the monitor did not measure fault current for the fault on the transmission system. This result is similar to Case 1 where the monitor was monitoring the Feeder 1 current only.

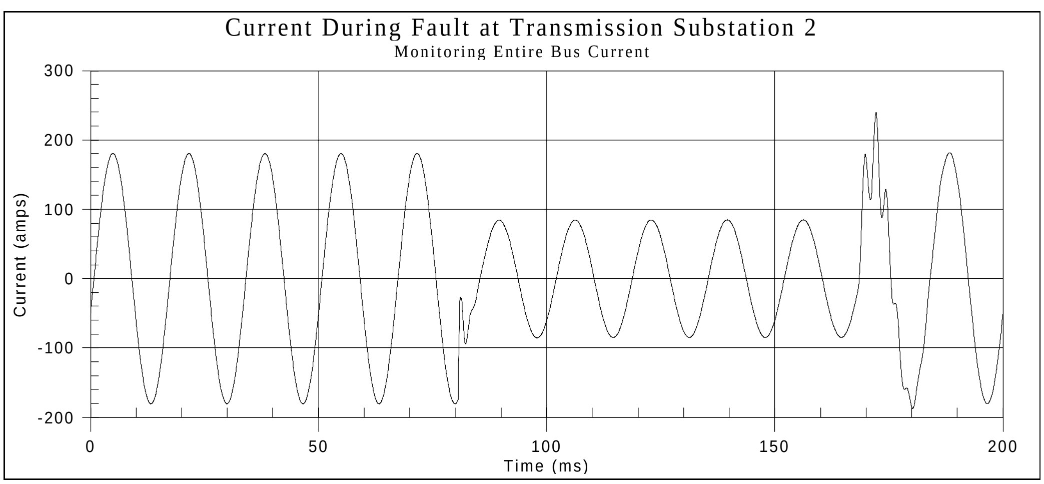


Figure 7-11
Results from Case 4: Monitoring at Substation 3 Transformer Secondary for Fault at Transmission Substation 2

Case 5: Fault Occurs on Feeder 2

For Case 5, a three-phase fault was placed on the high side of the transformer supplying Customer Bus #2. The fault was cleared in 5 cycles. Figure 7-12 illustrates the results from Case 5. As seen in Figure 7-12, the power quality monitor measures significant fault current during the fault. This is in contrast to Case 2, when the monitor did not measure any fault current during the fault on feeder 2.

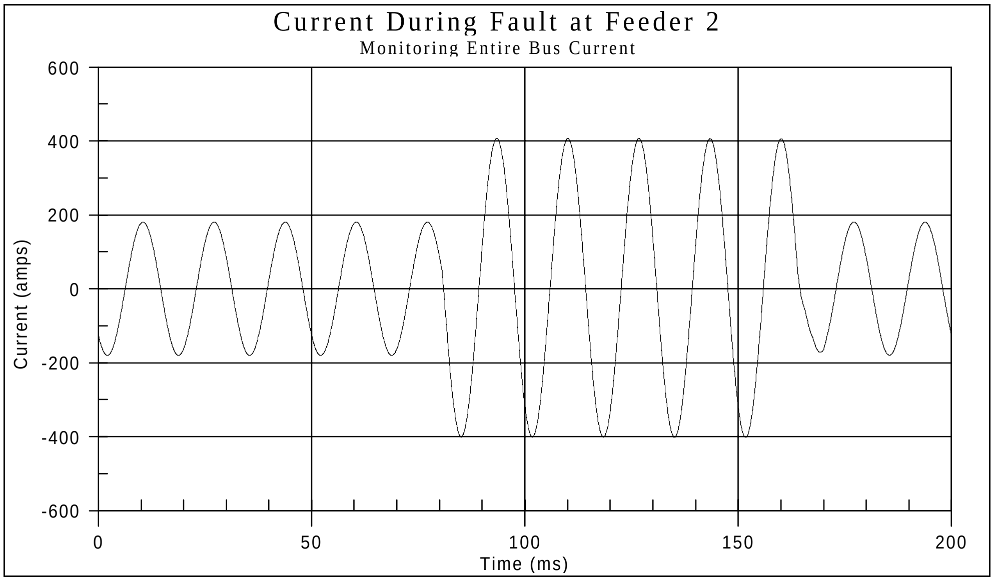


Figure 7-12
Results from Case 5: Fault on Feeder 2, Monitored at Substation 3 Transformer Secondary

Case 6: Fault Occurs on Feeder 1

For Case 6, a three-phase fault was placed on the high side of the transformer supplying Customer Bus #1. The fault was cleared in 6 cycles. The results from Case 6 are illustrated in Figure 7-13. Again, as in Case 3, the power quality monitor measured significant fault current during the fault on Feeder 1.

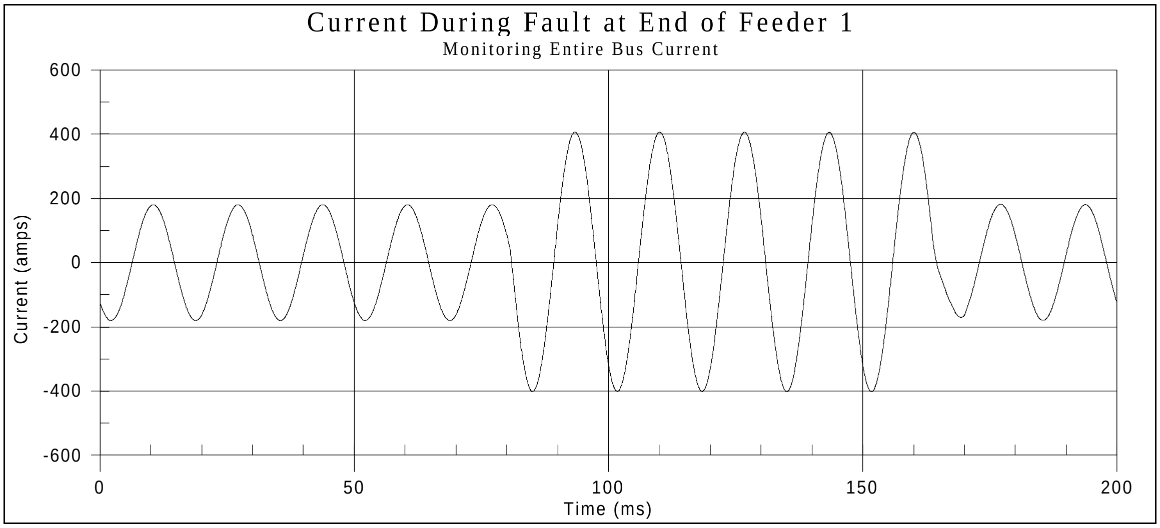


Figure 7-13
Results of Case 6: Fault on Feeder 1, Monitored at Substation 3 Transformer Secondary

Discussion

By monitoring the entire distribution bus current, upstream faults (transmission and substation transformer) are clearly distinguishable from downstream faults on the distribution system. Figure 7-11, which is a simulation of a fault on the transmission system at Transmission Substation 2, does not show the fault current flowing through the monitoring point. The other two figures (Figure 7-12 and Figure 7-13) show fault current flowing through the monitoring point, back to the source of the fault.

Although all six cases placed a three-phase fault on the system, other types of faults, such as single line-to-ground and phase-to-phase faults, would have similar results. The “location” or direction of voltage sags caused by high-impedance faults and motor starting can also be determined in this manner. The fault current my not be as significant as in the case of a bolted three-phase fault, but there should be a significant amount of current to make the determination.

Another point worth mentioning is the fact that that only current was measured in the simulations. In reality, the power quality monitors would measure voltages as well. In fact, most power quality monitors that are commercially available trigger on voltage only and therefore would be required in order to obtain a measurement. During the post-processing of the events, the current measurements would be analyzed to determine the direction of the event. If transmission-side CTs and PTs are not available, the entire bus on the distribution side can be monitored. A simple algorithm to differentiate between the transmission-side faults and the distribution-side faults is developed in the next section.

Implementation of the Algorithm

The algorithm used to determine the direction of the fault and ultimately the location of the voltage sag can be easily written and incorporated if the following information is available at the monitoring point:

- Short-circuit current at monitoring point.
- All three phases of current are measured.
- The entire bus current or distribution-transformer current is measured.

The algorithm is as follows (monitoring entire bus current):

IF

the measured current is approximately equal to the short-circuit availability

AND

the current does not decrease below the pre-fault current

THEN

the fault is downstream of the monitor

ELSE

the fault is upstream of the monitor

END IF

Table 7-5 illustrates the results of the algorithm after it was applied to all six cases. As illustrated in Table 7-5, the only cases that are correctly solved are where the entire bus current was measured (Cases 4, 5, and 6). The algorithm gives the wrong answer for Case 2 because it does not satisfy the first portion of the "IF" statement in the algorithm, which requires the fault current to increase above the pre-fault level.

Table 7-5
Example Application of the Algorithm to all Six Cases

Case #	Monitor Point	Fault Location	Algorithm Results
Case 1	Feeder 1	Transmission	Transmission
Case 2	Feeder 1	Distribution	Indeterminate
Case 3	Feeder 1	Distribution	Distribution
Case 4	Entire Bus	Transmission	Transmission
Case 5	Entire Bus	Distribution	Distribution
Case 6	Entire Bus	Distribution	Distribution

Extrapolation of Distribution-Level Monitoring of Voltage Sags to Transmission Level

The previous section illustrated that data from distribution-level monitoring could be used to determine whether events were initiated at the transmission level. The next logical step in this process is to transform the distribution measurements (actual values measured) to the transmission level. If all the measurements were performed in percent or on a per-unit basis, and the effects of the distribution transformers were neglected, this step would not be required. However, due o the impedance in the distribution transformers and the various connection types (delta-wye, wye-wye, and so on), transformation of the measurements is required.

The basic transformation requires two steps. The basic transformation is the ratio of the voltage on the distribution side of the transformer to the voltage on the transmission side of the transformer. The shift in phase angle, if any, is also taken into account in this step. In order to perform the transformation, certain data is required. This data includes:

- Transformer primary and secondary connections.
- Nominal voltages on primary and secondary side.

To apply the transformation, the following must be performed:

Step 1: Phase Angle Shift

Referring to the transformer nameplate or test sheet, the shift in phase angle can be determined. For instance, in the case of a delta-wye transformer, the phase angle is shifted plus-or-minus 30 degrees, depending on the convention used and the rotation of the phase voltages. One should not automatically assume that, for example, a wye-wye transformer connection has zero degrees of shift. Always refer to the nameplate or test sheet data.

Step 2: Voltage Shift

To make the voltage shift, first determine the primary and secondary voltages that are available and desired. If the primary voltage desired is line-to-neutral and the secondary voltages available from the monitor are line-to-neutral, then only the turn ratio need be applied. On the other hand, if there is a desire for line-to-line primary voltages derived from secondary line-to-neutral voltages, then the voltage is increased by a factor of 1.73 (the square root of 3) after applying the turn ratio.

One case is used to validate the method described for transforming events from the distribution side of a transformer to the transmission side of the transformer. This example builds upon the transmission fault (Case 1) in the previous section. As a reminder, a three-phase fault occurs at the bus of Transmission Substation 2 and is cleared in 5 cycles.

The voltage waveform measured at the 13.2-kV bus (line-to-ground) is illustrated in Figure 7-14.

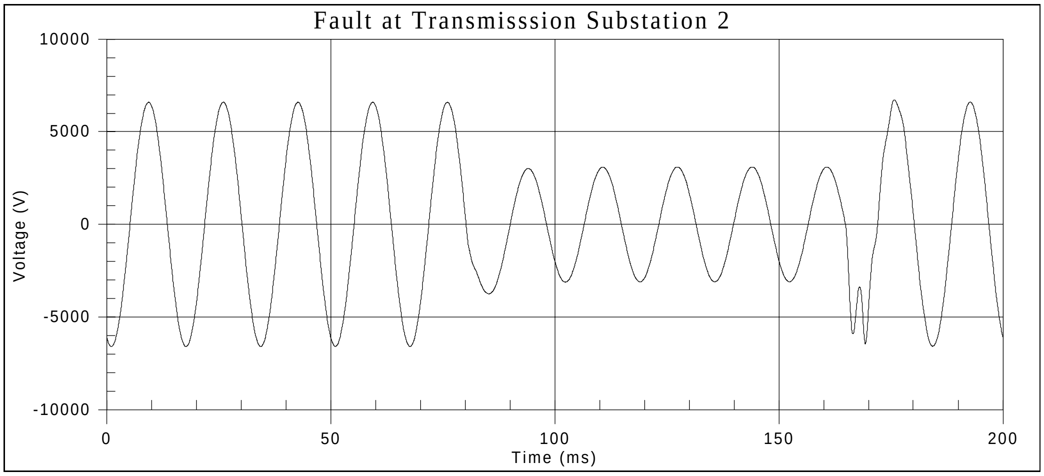


Figure 7-14
Voltage Recorded (Line-to-Ground) on the 13.2-kV Bus of Substation 3

The results of the first step are illustrated in Figure 7-15. Using this approach of voltage transformation produces a waveform that closely matches the actual measured data. However, the secondary voltages do not exactly match the primary voltages at high frequencies. A clearer view of this mismatch is illustrated in Figure 7-16. This is either due to the inaccuracy of the transformer model or, more likely, the interaction between the sag and the system components (particularly capacitor banks) on the secondary. To determine the cause, another simulation was performed with all the capacitors removed from the distribution system. Notice the near exact match (Figure 7-17) between the calculated and actual primary voltages. This points toward components on the distribution system causing the ringing.

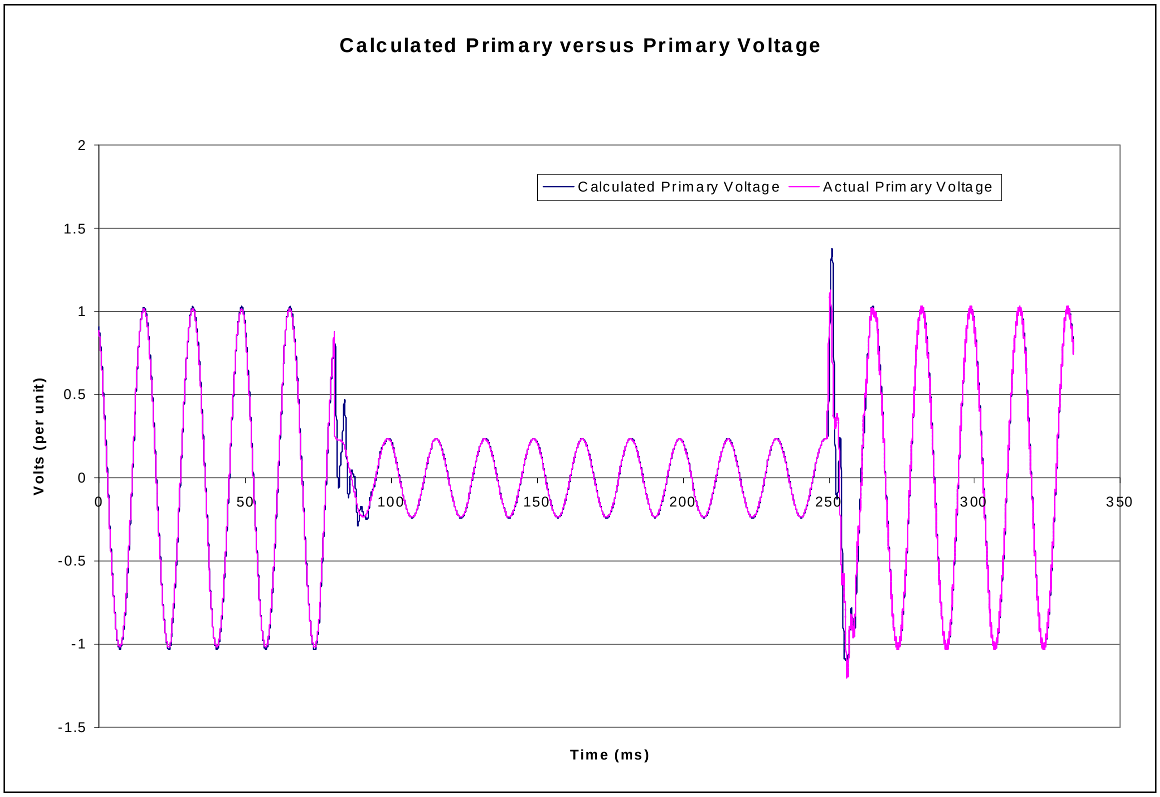


Figure 7-15
Primary Voltage Calculated from Secondary Voltage as Compared to Measured Primary Voltage

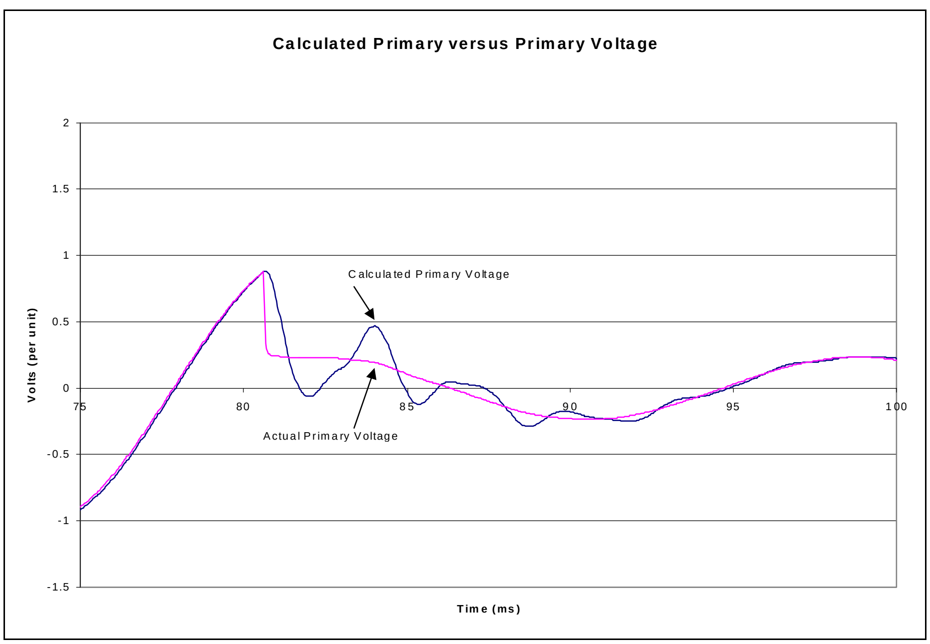


Figure 7-16
Initiation of Fault Zoomed in to Show Mismatch between Calculated Voltage and Actual Voltage

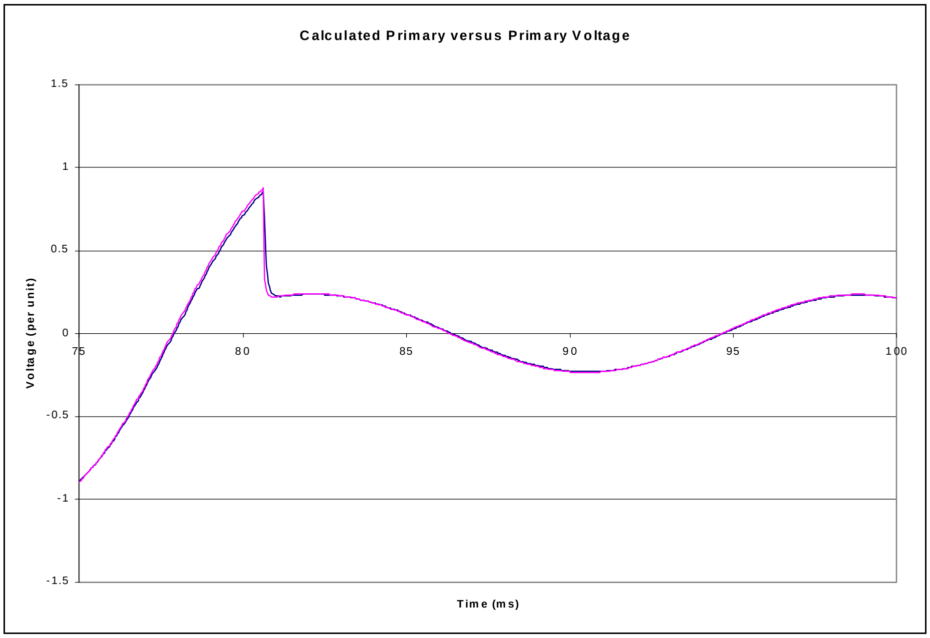


Figure 7-17
Calculated Primary Voltage versus Actual Primary Voltage without Any Distribution-Side Capacitors

Case 2: Single Phase-to-Ground Fault on the 115-kV Transmission System at Substation Bus 2

The second case performed for verification of the voltage transformation from the distribution side to the transmission side was to place a single line-to-ground fault on the 115-kV transmission system. The simulation was preformed with all the capacitors taken out of service.

As illustrated in Figure 7-18, there is good correlation between the distribution voltages and the transmission voltages. In fact, all three phase voltages agree within approximately 1%.

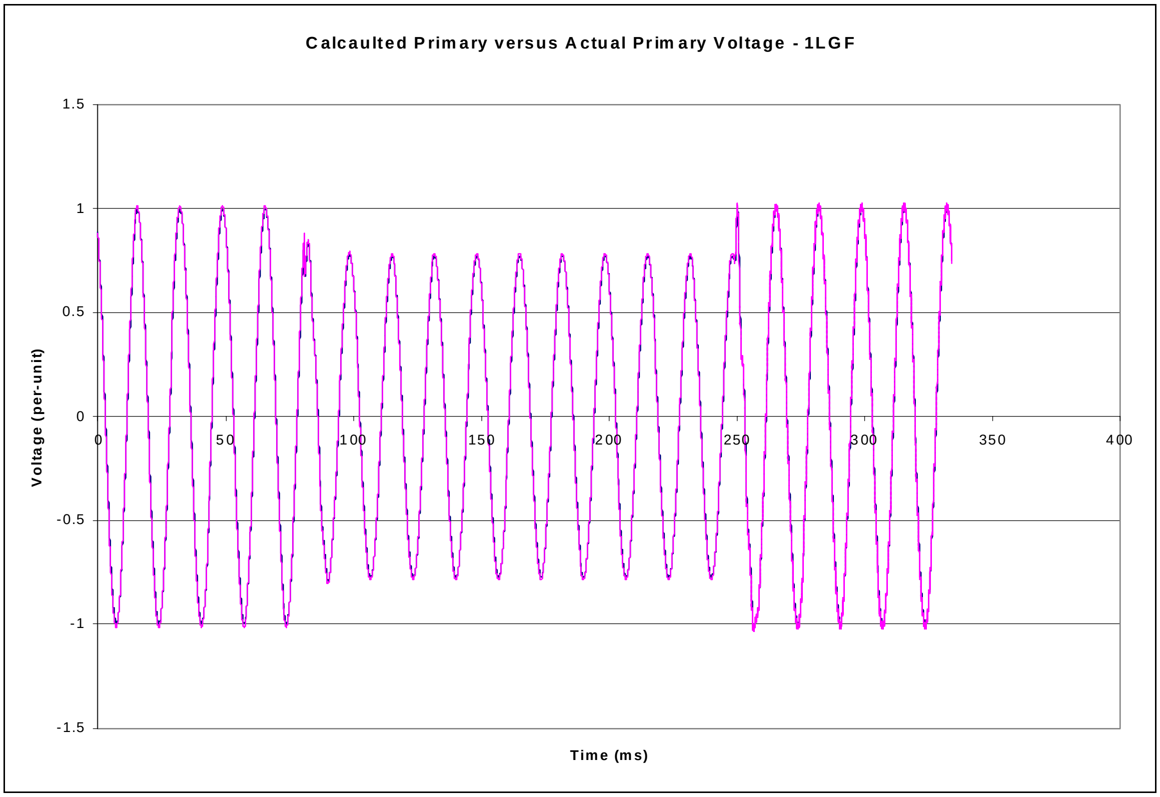


Figure 7-18
Single Phase-to-Ground Fault on the Transmission (Primary) Side (Primary Voltage Compared to Secondary Voltage)

Extrapolation of Distribution-Level Monitoring of Harmonics to Transmission Level

The ability to measure power quality on the distribution system and extrapolate that information to the transmission system has great benefit. As shown in the previous section, the algorithms and techniques required to perform this for voltage variations is straightforward. This section deals with the techniques and methodologies required to perform the same extrapolation for harmonic voltages and currents.

In order to attempt this extrapolation, certain system parameters and characteristics must be known. In the most basic case, as in Figure 7-19, the information required is:

- Transmission equivalent impedance at the primary of the transformer.
- Transformer size.
- Transformer impedance.
- Transformer X/R ratio.
- Transformer connections.
- Nominal voltages on transformer.

The process for obtaining harmonic information on the transmission system from measurements at the distribution system should be a fairly straightforward process. The following three steps outline the process that is used:

1. Using the measured current on the distribution side of the transformer, scale it to the transmission side of the transformer via the transformer turns ratio. Take into account any phase shift caused by transformer connections.

2. Multiply the current from Step 1 by the equivalent impedance of the transmission system.

3. Filter (numerically) any harmonics that are not reflected through the transformer as needed.

Two cases are given as examples of this process.

Case 1: 2000-HP ASD Applied at the 13.2-kV Bus with Linear Load

Case 1 has a 2000-HP adjustable-speed drive (ASD) connected to the 13.2-kV bus. The drive generates primarily 5th and 7th harmonics. The system model also includes an additional 1 MVA (at 0.9 lagging power factor) of linear load. This can be seen in Figure 7-19.

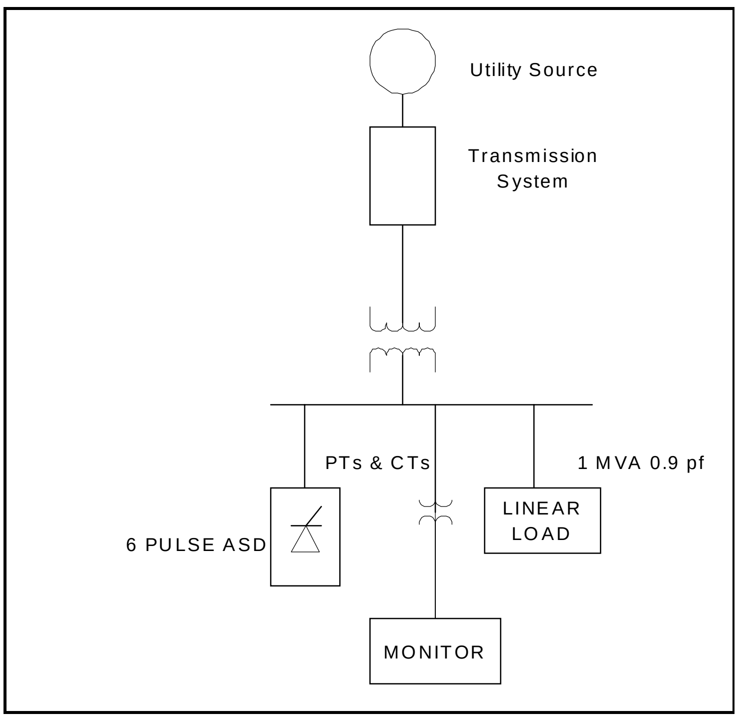


Figure 7-19
One-Line Diagram of System Under Simulation

The current as measured on the 13.2-kV bus is shown in Figure 7-20. The total harmonic current distortion is 19.9%, and the RMS current is 133.1 amps. The harmonic spectrum for the current measured on the 13.3-kV bus is illustrated in Figure 7-21.

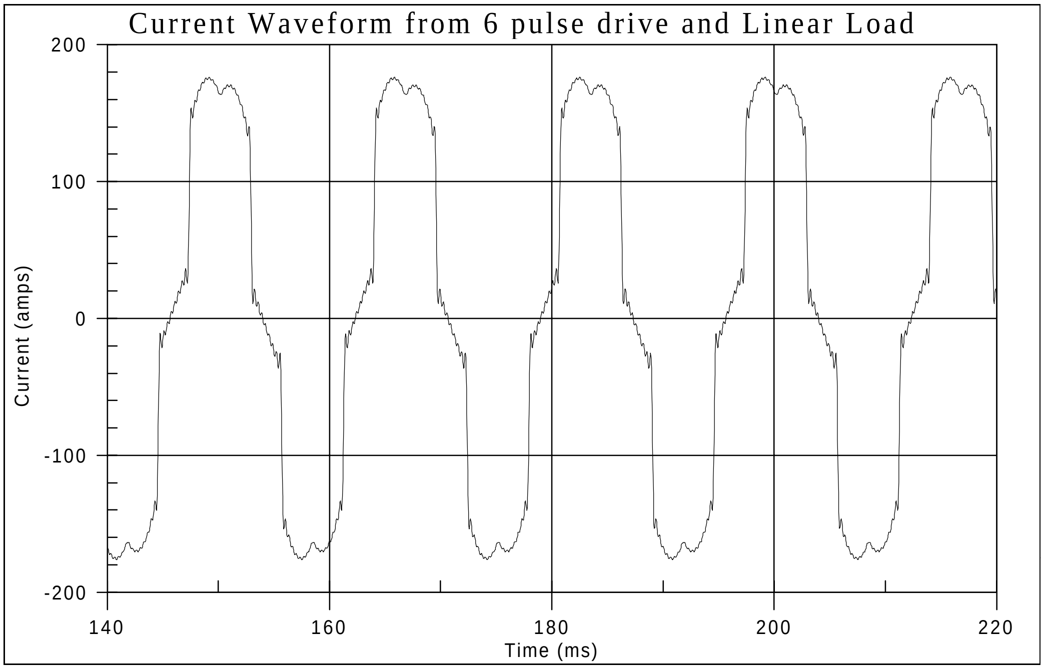


Figure 7-20
Current from 13.2-kV 6-Pulse Current Source Inverter Drive and 1-MVA Linear Load

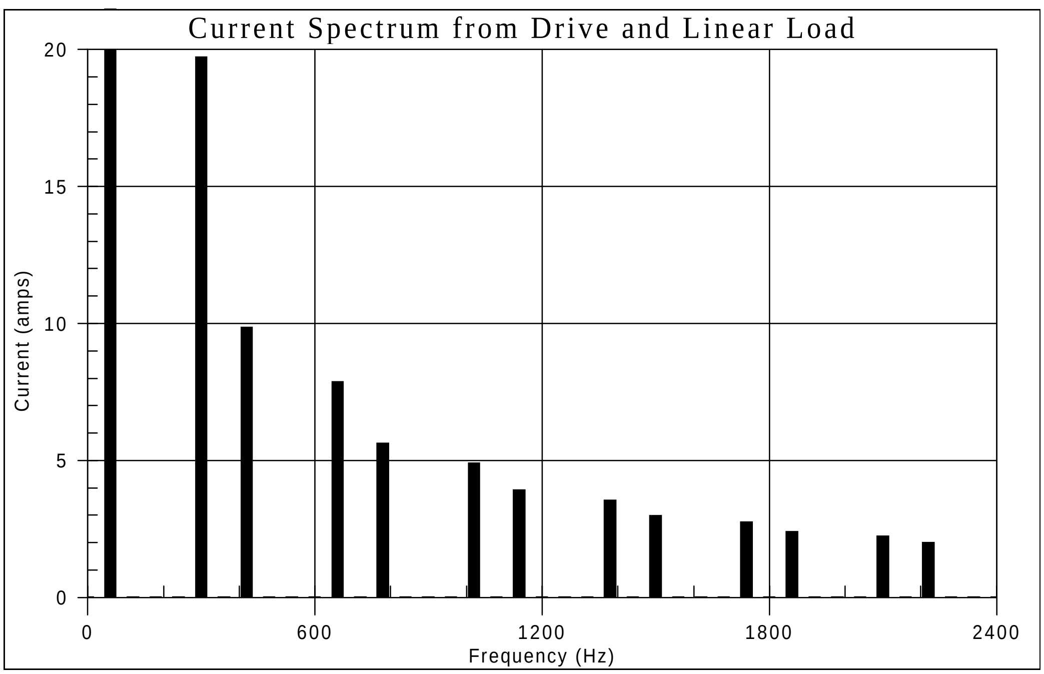


Figure 7-21
Current Harmonic Distortion Spectrum

Using the three-step approach from above, the first step was to determine the equivalent impedance of the transmission system, separate from the transformer. This was achieved by performing a harmonic impedance scan with just the transmission impedances present. The impedance scan was performed in PCFLO provided by Dr. Mack Grady, who is with the University of Texas at Austin, free of charge.

The results of the impedance scan can be found in Table 7-6. All impedances are given in percent based on a 115-kV, 100-MVA base. The harmonic numbers are multiples of 60 Hz. Additionally, the impedances for the transformer were also calculated in PCFLO for each harmonic up to the 25th. These impedances were calculated on the same base as the transmission system equivalents and appear in Table 7-6 as well.

Table 7-6
Transmission System Impedances and Transformer Impedances in Percent on a 115-kV, 100-MVA Base

Transmission			Transformer		
Harmonic #	**R (%)**	**X (%)**	**Harmonic #**	**R (%)**	**X (%)**
1	3.23	23.30	1	50.50	5.04
2	3.26	46.59	2	50.51	10.09
3	3.30	69.89	3	50.51	15.15
4	3.25	93.19	4	50.51	20.20
5	3.25	116.48	5	50.50	25.29
6	3.17	139.78	6	50.51	30.35
7	3.13	163.08	7	50.53	35.38
8	3.25	186.37	8	50.51	40.47
9	3.29	209.67	9	50.53	45.50
10	3.25	232.97	10	50.46	50.64
11	3.13	256.27	11	50.48	55.68
12	3.42	279.56	12	50.45	60.76
13	3.17	302.86	13	50.48	65.79
14	3.42	326.15	14	50.52	70.83
15	3.05	349.45	15	50.45	75.93
16	3.25	372.75	16	50.56	80.92
17	3.46	396.04	17	50.48	86.03
18	2.93	419.34	18	50.49	91.09
19	3.09	442.64	19	50.48	96.15
20	3.25	465.93	20	50.47	101.22
21	3.42	489.23	21	50.46	106.28
22	3.58	512.53	22	50.50	111.32
23	2.81	535.83	23	50.59	116.34
24	2.93	559.12	24	50.54	121.42
25	3.05	582.42	25	50.58	126.47

Using the impedance values from Table 7-6, the current waveform was reflected to the 115-kV side of the transformer. The triplen harmonics were set to zero amps to account for the delta-wye transformation. Next, the impedances were added together and multiplied times the current to obtain the harmonic voltages.

A simple voltage-divider circuit was set up to calculate what the harmonic voltages would be on the primary side of the transformer. The resulting voltage THD was 0.3%. This is approximately half of the value that was simulated.

It appears that, even with a simple circuit, the voltage-divider method does not produce accurate results. It is likely that significant modeling would have to be done in near real-time to place the corrected (reflected) voltage and current harmonic waveforms into a database or other file/memory storage.

Extrapolation of Distribution-Level Monitoring of Capacitor-Switching Events to Transmission Level

Another power quality concern for transmission systems is capacitor-switching transients, or any type of switching transient for that matter. In this section, the method used to determine the relative position of switching events, in reference to the monitor, are evaluated. As with the other sections in this chapter, the idea is to be able to utilize distribution-level power quality monitors and to be able to distinguish between transmission-level events and distribution-level events.

One method used to determine the direction (upstream or downstream) of a switching event is to use two quantities: the disturbance power and disturbance energy [7]. Disturbance power is defined by:

$$DisturbancePower(t) = p(t)_f - p(t)_{SS} \qquad \textbf{(7-2)}$$

where

- $p(t)_f$ is the power during the fault as a function of time.
- $p(t)_{SS}$ is the steady-state power as a function of time.

Disturbance energy is simply the integral of the disturbance power. The meter used for this analysis must be capable of determining the exact beginning and the exact end of the disturbance. If not, the disturbance energy and disturbance power cannot be calculated correctly. The theory is that if the disturbance energy initially goes negative, then the event is upstream from the monitor. If the disturbance energy initially goes positive, then the event is downstream from the monitor.

Two simulation cases were performed to verify the disturbance-power method of identifying the direction of switching events.

Case 1: Transmission (Upstream) Capacitor Switched While Monitoring Distribution Bus

For Case 1, the 25-MVAR capacitor bank at Transmission Substation Number 2 was switched. See for the one line diagram in Figure 7-22 for the location of the capacitor bank. Based upon measured data, the disturbance power and disturbance energy were calculated. The disturbance energy is of particular interest in this case. The disturbance energy shows the direction of the event relative to the monitor. The negative-going initial portion shows that the capacitor being switched is upstream of the monitoring point. The plot for the disturbance energy is illustrated in Figure 7-23.

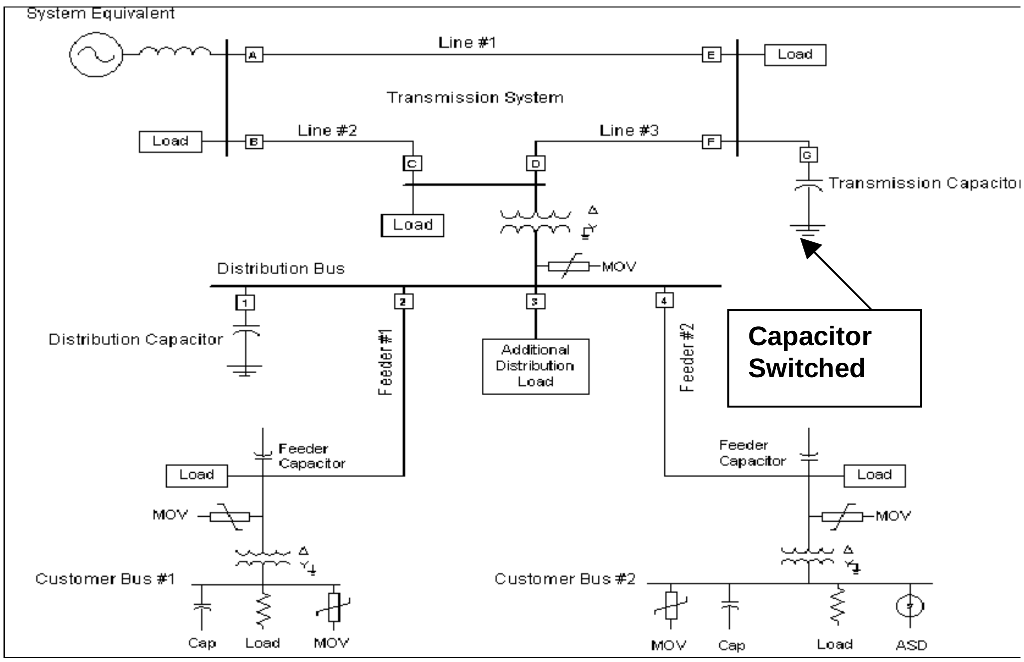


Figure 7-22
One-Line Diagram Indicating Capacitor that is Being Switched for Case 1

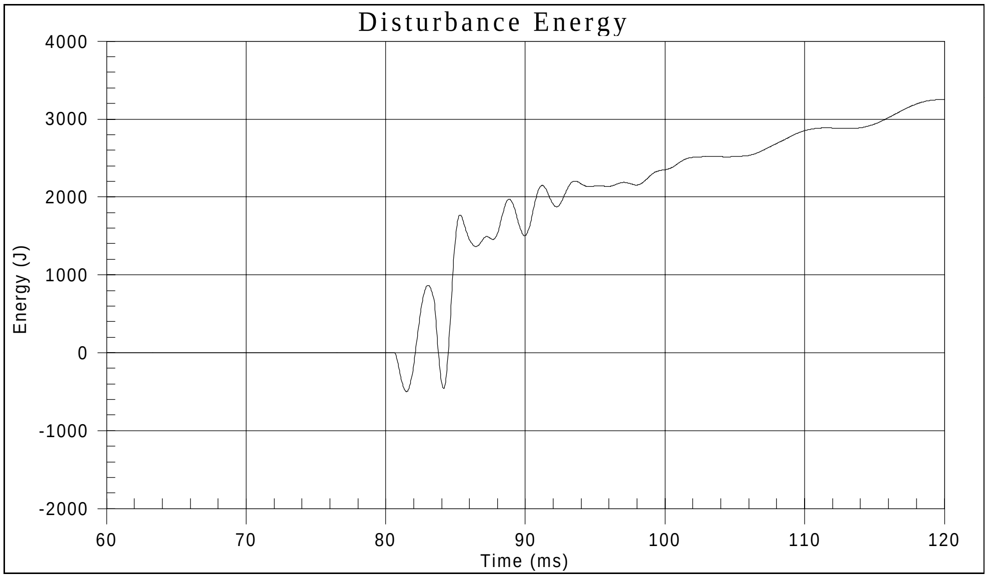


Figure 7-23
Disturbance Energy for Switching Event Upstream of the Monitor (Note Negative-Going Initial Energy, Showing Direction)

Case 2: Distribution (Downstream) Capacitor Switched While Monitoring the Distribution Bus

In Case 2, the distribution-level capacitor on the 13.8-kV bus is switched, which is downstream from the monitoring point as illustrated in Figure 7-24. In opposition to Case 1 in this section, the energy initially goes in a positive direction, indicating that the capacitor being switched is downstream of the monitoring point. The disturbance energy for Case 2 is plotted in Figure 7-25.

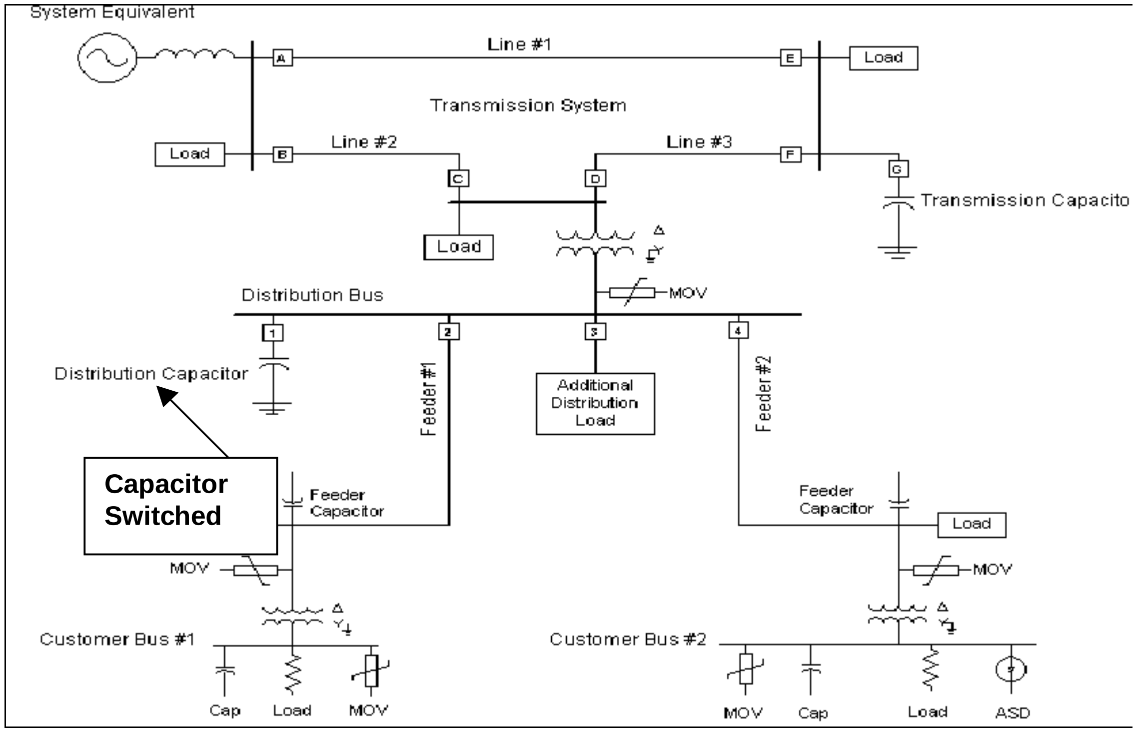


Figure 7-24
One-Line Diagram Indicating Capacitor that is Being Switched for Case 2

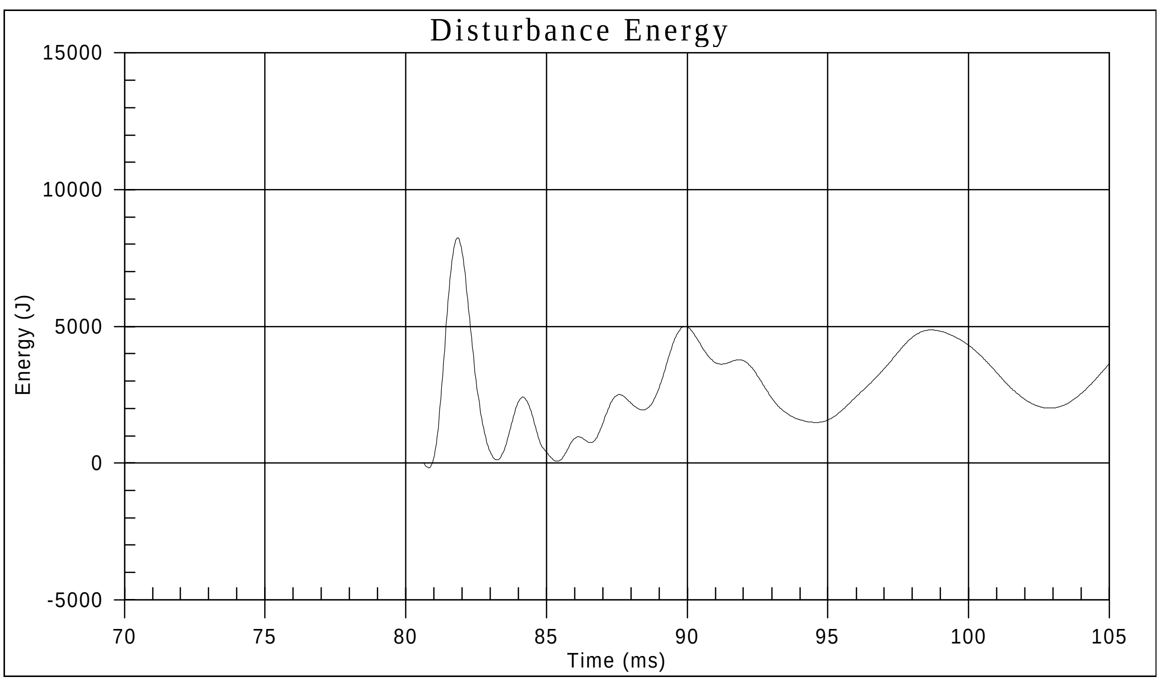


Figure 7-25
Figure Showing Disturbance Energy Due to Downstream Switching of a Capacitor Bank

Discussion

By using the disturbance-energy method for determining switching direction, the location of a switching event can be determined with confidence. This proves very valuable to our efforts. This method will allow the use of distribution-level power quality monitors for transmission-level benchmarking, provided that the appropriate monitors are in place or installed as part of a transmission-level power quality benchmarking project.

If the power quality instruments selected for a transmission-level project do not incorporate this algorithm, the detection of a switching event will be determined in the post-processing stage of the measurement program. Events that are classified as distribution-level events will be removed from the measurement database.

Conclusions

Directly monitoring the transmission provides the most accurate results. However, due to cost limitations, accessibility, and other factors, using existing distribution-level monitors has merit. Algorithms can be developed that determine which events are distribution-level events and which events are transmission-level events. The algorithms will also transform the measured distribution-level quantities to the transmission system.

Power quality monitors are currently being developed by several manufacturers that allow these algorithms to be embedded in the instrument. If more traditional power quality monitors are used, the algorithms can be developed to be used in the post-processing stage of data collection and analysis.

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8
METHODOLOGY FOR INCORPORATING A VOLTAGE SAG STATE ESTIMATOR

Overview

Energy consumers are increasingly utilizing devices that are more sensitive to subtle power quality variations such as voltage sags. Many utilities are responding to consumer power quality concerns by developing a better understanding of the quality of service being offered to the customer base. Unfortunately, developing and maintaining a power quality data-gathering infrastructure is costly. Procurement and installation of a single power quality monitor may cost tens of thousands of dollars. These costs allow utilities to monitor only a very small subset of their power systems. Furthermore, due to costs and proximity to the end user, most national and individual-utility benchmarking efforts have generally included only distribution-level busses, ignoring transmission-level power quality. This chapter describes a "Voltage Sag State Estimator" that will provide participating utilities with a software tool that leverages existing short-circuit models and a limited number of power quality monitors to estimate voltage-sag performance at every distribution and transmission substation bus.

Utilities around the world have participated in both national and individual-utility studies to benchmark power quality at the distribution level. Considerably less effort has been directed at benchmarking transmission power quality levels due to the relative proximity to the end user, the additional costs of monitoring at this level, and the fact that transmission events are indirectly included in distribution assessments. The practice of serving large, influential customers from the transmission level and the unbundling of the traditional vertically-integrated utility into generation, transmission, and distribution companies increase the need for assessing transmission performance independent of distribution performance.

RMS voltage variations (voltage sags and swells) are an important benchmark characterization for a transmission system because they are indicative of the overall health of the transmission system. An increase in the number or severity of events may indicate that certain maintenance issues need to be addressed while absolute values outside of industry averages may suggest that some fundamental design issues need to be re-evaluated.

A software tool for estimating voltage-sag performance provides the means for utilities to assess the sag performance of the total transmission system. This assessment is not a statistical representation based on a defined statistical site-selection process, stratification variables, and weighting factors. Unlike virtually all power quality benchmarking projects performed to date, this approach allows the voltage-sag performance for every transmission delivery point and secondary bus of every distribution substation to be quantified with only a limited number of actual monitors.

It is anticipated that reasonably accurate RMS voltage variations could be calculated for each bus if 10% of the buses for each transmission voltage level were equipped with monitoring equipment sufficient to record RMS voltage variations. The distribution of these 10% should be somewhat uniform from a geographical point of view in order to provide a variety of “electrical closeness” between the recorder and the fault for each fault condition.

The state estimator uses the monitoring results from existing monitoring locations along with information from an operations database and a short-circuit representation of the system to estimate the fault location, type, and impedance. It then calculates the voltage-sag characteristics for all buses. Both the calculated and actual sag information is maintained in the power quality monitoring database. Subsequent data analysis and reporting is accomplished with third party software capable of analyzing power quality measurement data. In other words, the voltage sag estimator expands the monitoring system to include all buses in the system without actually having monitors at all the buses. A flow diagram for this approach is shown in Figure 8-1.

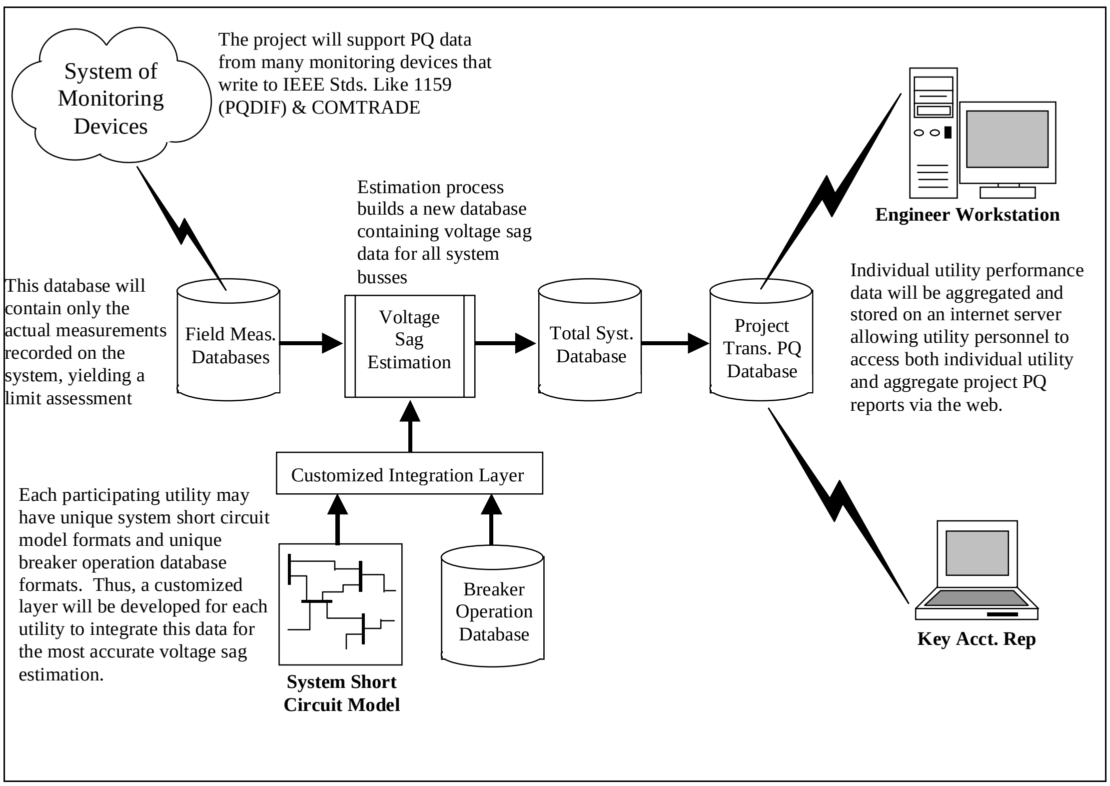

Figure 8-1
Data Flowchart for a Voltage Sag State Estimator System

This estimator is designed to predict voltages and currents during short-circuit fault events on the transmission system. The general approach is to try to figure out where the fault occurred, what type it was, and the impedance of the fault. The resulting voltage profiles on all system buses can then be calculated from the system impedance or admittance matrix once the fault has been properly characterized. The calculated profiles can then be added to the power quality measurement database with an appropriate flag indicating that they were calculated. An additional indicator reflecting the tolerance and/or certainty of this calculation can also be added.

The accuracy with which the state estimator can identify the fault location and impedance will vary depending upon what information is available and the relative location of the fault to any monitoring equipment. Fortunately, a high degree of accuracy is probably not required to achieve a reasonable estimate of state variables suitable for computing voltage-sag indices. For example, the proposed voltage-sag indices have relatively coarse intervals (90%, 70%, 50%, and 10%). A voltage sag of 55% falls in the same bin as one of 65%, so the estimate can have a significant error while still yielding meaningful indices.

Algorithm Requirements of the Voltage Sag State Estimator

The voltage sag state estimator consists of several different modules. These modules can be broadly characterized as database interface modules, a calculation module, and a reporting module. The dominant requirements for each of these modules are described below.

Database Interface Modules

The voltage sag state estimator software should interface seamlessly with the existing short-circuit computer model database, the breaker operation database, and the power quality monitoring database. This typically requires a complete mapping of node identifiers between the three different databases because they often have different identifiers for the same node. The interface to each of the three different databases needs to be self contained and easily modifiable in order to support different formats and/or modifications to the database structure.

The short-circuit database consists of a detailed three-phase model of the transmission/distribution system. It contains impedance information for all of the branches in the model as well as transformer tap settings and connection configurations (delta-delta or delta-wye). It also contains Thevenin equivalent models for all of the potential sources of the short-circuit current.

Many short-circuit databases are based on proprietary formats, which can vary over time as new versions of a short-circuit program are released. The basic strategy for this database interface is to have it consist of numerous “add in” modules. Each of these modules would be capable of translating unique or proprietary formats into a standardized internal database format. The interface should also be capable of importing a simple ASCII comma-separated file with a predefined format.

The breaker-operations database keeps track of each breaker’s operating position (either open or closed) as a function of time. This database also needs to keep track of the same information for disconnect switches, circuit switchers, and isolation links. The interface to the breaker-operation database needs to have characteristics similar to those previously outlined for the short-circuit database interface. In addition, the standardized internal format for the breaker-operation database needs to be relational with the internal format of the short-circuit database. This allows the sag estimator tool to configure the internal electrical model to match the actual configuration of the system before, during, and after the fault condition.

The power quality monitoring database will consist of voltage and current information recorded by a variety of different monitors throughout the system. The type and format of this information will vary widely. The interface to this data should be based on an industry standard format such as the IEEE PQDIF format. Each record in this database will have to be mapped to a particular node in the internal short-circuit database as well as to a particular point in time in the internal breaker-operation database. The accuracy of the information from each monitoring location is going to be different depending on the accuracy of the transducers, monitor accuracy, and calibration procedures. It will be necessary to assign an accuracy-weighting factor to each piece of monitored data.

Calculation Module

The role of the calculation module is to identify the fault location and the associated fault impedance for each sag event. This module must also calculate the resulting voltage profiles at each system bus for each fault condition.

The calculation module must be based on a complete three-phase representation of the system. This is necessary because a line-to-ground fault will result in very different profiles than a three-phase fault. Delta-wye transformations also significantly alter the voltage profiles. It will need to be able to accept three-phase information (voltages and currents) and will need to be able to build a three-phase short-circuit model of the electrical system that is consistent with the breaker-operation database. Standard analysis algorithms and system data are often based on positive-, negative-, and zero-sequence parameters, so the necessary routines for the transformation between phase and sequence quantities are also required.

For each sag event, the calculation module first reads the various databases and builds an internal electrical model of the system that reflects the configuration just prior to the fault. It then begins the process of identifying the fault location and fault impedance (if any).

The calculation module needs to be able to work with a combination of different input signals. It will need to process information about voltage, current, and breaker operation, but it should not rely on all of that information being available for all of the sags. It also needs to accept different types of monitored data. It should have the flexibility to process RMS or waveform data as well as characterized data.

The calculation module needs to be able to work with a variable amount of monitored data. In general, the more information available, the higher the accuracy associated with identification of the fault location. After reading all of the data, the calculation module must filter out and disregard any suspicious or bad data. A blown PT fuse and a faulty monitor are likely sources for bad data. The module should also flag and disregard any inconsistent data. Current flowing in a branch that is reported to be opened is a classical inconsistency problem.

The calculation module will use different fault-location algorithms or procedures depending upon what data is available. A typical sequence would be:

1. Identify the specific faulted line.

2. Identify the type of fault (phase-to-phase, phase-to-ground, and so on).

3. Identify the fault location along the line and any fault impedance.

A possible scenario would be that the breaker-operation database could clearly identify what line experienced the fault, monitored currents could identify what phases were involved, and the monitored voltage profiles could be used to pinpoint the fault location and impedance. A scenario with less available data would have to employ a different and more computationally intensive approach.

The fault-location algorithm will also need to employ a state-estimation technique such as a “weighted least squares” approach to minimizing the square of the error between the measurements and the computed estimates of the measured quantities. The weights used in this approach would be assigned according to the accuracy of the measurements. The measurements with a higher accuracy would receive a higher weight. By iterating through an optimization solution procedure, estimates for the circuit variables are obtained. This technique is used to decide if one proposed fault location/impedance is better than another.

Once the fault type, location, and impedance have been determined, the calculation module must then calculate the voltage-sag profiles for each node on the system. The magnitude of the sag at each node is easily derivable using either the admittance or impedance matrix of the network. The duration of the sag would be derived from either the breaker-operation database or by changes in the monitored voltages and/or currents. The calculation module should also assign an accuracy indicator for each profile that is reflective of the quality of the voltage sag profile estimation. This will depend upon the available input data as well as the relative location of the node being reported to both the fault and any monitored nodes.

Reporting Module

The reporting module needs to translate each calculated voltage profile into a standard format such as the IEEE PQDIF format and make it available much like a real monitor would. Each calculated profile would be indexed to a particular node in the electrical model and to a particular point in time. In addition, the derived accuracy indicator would also need to be reported with each calculated profile.

9
COMPARISON OF METHODOLOGIES

The previous sections described, in detail, three different methods for determining power quality levels on transmission systems. This type of study is commonly referred to as benchmarking. Previous studies have been performed to benchmark power quality levels in customer facilities and on distribution systems. These studies are cited in the bibliography section of this chapter. This section focuses on comparing the three described methods. The advantages and disadvantages of each method are given.

Estimation Method

The estimation method typically requires information on the system in the form of a system model and historical line performance. The system model typically consists of line lengths, line impedances, transformer information, and short-circuit MVA of the system. Most fault studies require this data. Fault studies allow the estimation of system performance during sudden changes in load, such as voltage drop due to a motor start. The available fault current at different points in the system may be calculated for protective-device studies. More advanced fault studies have relay models and recloser and fuse curves, which may be used to perform coordination studies.

Advantages of Estimation Method

The advantage of using a stochastic prediction method is that system performance estimates may be made quickly based on readily available system information. Voltage-sag data gathered during fault studies can be very accurate. This is also true for fault-duration data if protective device-models are incorporated into the system analysis. Because stochastic prediction methods rely on modeled and historic line-performance data, estimates may be performed on systems not yet constructed.

The estimation method also eliminates the need to install monitors on the power system. This is a big advantage in the fact that the cost to install and maintain monitoring instruments can be quite high. Several utilities have reported costs in the range of $10,000 to $50,000 per monitoring site for installation.

Disadvantages of Estimation Method

Stochastic prediction methods are only as accurate as the data provided. If the system model is constructed without attention to detail or not maintained with system changes, estimates may be poor. The variable, which is the most subject to change, is the frequency of faults at the system. This variable depends upon season, weather, line-clearance practices, animal contact, and catastrophic events. Therefore, the frequency of events associated with a stochastic estimate may often be a subject of suspicion.

Measurement Method

The measurement method uses actual measurements to benchmark power quality levels on a given system. These measurements are generally performed at the transmission level or voltage level of interest. Some research was performed in the area of using existing distribution-level monitors and extrapolating the measurements to the transmission level.

Advantages of Measurement Method

The advantage of the measurement method is the actual measurement data itself. Having actual measurement data takes the guesswork out of determining the frequency and duration of power quality events. However, all measurement data is historical, and using measurement data to predict future power quality events may be suspect.

Measurements also allow a utility to build a very concise historical database of all types of power quality phenomena regardless of the benchmarking project. If a utility is interested in reliability benchmarking and gathers data for several years, this same measurement data, depending on the monitoring instrument, may be used to benchmark harmonics, transients, or other power quality phenomena in the future.

Monitoring of the distribution system is a viable and cost-effective approach for determining the power quality levels on the transmission system. This approach takes advantage of existing distribution monitoring points, which are typically less expensive to install and maintain than transmission-level monitors. By developing algorithms to distinguish transmission-level events from distribution-level events, distribution-level monitors can be used. Algorithms to “reflect” the quantities from the distribution system to the transmission system also need to be developed.

Disadvantages of Measurement Method

The only real disadvantage to the measurement method is the cost associated with installing power quality monitors. However, as mentioned in previous sections, many utilities have devices installed on the power system that can provide the information needed for voltage-sag or reliability benchmarking. More sophisticated instrumentation may need to be installed if transients and harmonics are of interest.

A disadvantage to using distribution-level power quality monitors, which is easily overcome, is the need for the algorithms that distinguish distribution-level events from transmission-level events and algorithms that transform the quantities measured on the distribution system to the transmission system. These algorithms can be embedded in the power quality instruments or they can be developed to operate on the data in post-processing software.

Hybrid – State Estimation

The hybrid method uses both measurements and estimation to benchmark the power quality levels on a given system. A voltage sag estimator software tool provides the means for utilities to assess the voltage-sag performance of the total transmission system. This assessment is not a statistical representation based on a defined statistical site-selection process, stratification variables, and weighting factors. Unlike virtually all power quality benchmarking projects performed to date, this approach allows the voltage-sag performance for every transmission delivery point and distribution substation secondary bus to be quantified with only a limited number of actual monitors.

Reasonably accurate RMS voltage variations can be calculated for each bus if 10% of the buses for each transmission voltage level are equipped with monitoring equipment sufficient to record RMS voltage variations. The distribution of these 10% should be somewhat uniform from a geographical point of view in order to provide a variety of “electrical closeness” between the recorder and the fault for each fault condition.

Advantages of State Estimation Method

The advantage of the state estimation method is that it incorporates monitoring and simulations. Only 10% of the busses on a system need to be monitored. This greatly reduces the capital outlay for a utility that does not have instrumentation at the transmission level. Voltage-sag and reliability indices can be calculated using the state estimator software for any bus in the system.

Disadvantages of the State Estimation Method

The disadvantage of the state estimation method is that, as of the date of this report, no state estimation software or system has been developed.

Conclusions

All three benchmarking methods described have merit and have a place in analyzing and benchmarking transmission systems. Depending on the goals of the benchmarking project and the utility conducting the benchmarking project, the appropriate method will vary.

Utilities that have an extensive distribution-level power quality monitoring program in place might find the distribution monitoring method more economical and efficient than the other methods presented. A utility without a monitoring program may opt for the state estimation method. By installing a limited number of monitors, very accurate results can be obtained by using the state estimation method. Utilities with a limited budget but with accurate system and historical data may find the estimation method acceptable. By using software that allows for entering reclosing schemes, very accurate voltage-sag and reliability indices can be calculated for distinct system configurations.

10
CONCLUSIONS

The main objective of the Transmission Power Quality Benchmarking Methodology Project is to determine what techniques could be used to benchmark transmission systems. Three techniques were evaluated in this report: short-circuit simulations, monitoring, and state estimation. All three methods proved to be viable for benchmarking transmission systems to some extent. Some of the more relevant findings are:

- Using short-circuit analysis software is a viable alternative to performing actual monitoring on the transmission system. A more accurate picture of voltage variations can be presented if the simulation software provides a means to incorporate utility fault-clearing schemes and detailed historical data on the transmission system.
- Actual monitoring of the transmission system provides a greater accuracy than short-circuit analysis techniques. Monitoring at the transmission level is preferred for benchmarking the transmission system, but simulations have shown that algorithms can be developed that allow the use of less costly monitoring at the distribution level for benchmarking the transmission system. In this case, software must be developed to allow for the recognition of upstream versus downstream events. Once the event direction has been determined, the software must also transform the event to the transmission level.
- Using distribution-system monitors for benchmarking harmonics on the transmission system did not prove to be a feasible alternative to monitoring directly at the transmission level. Determining the source of harmonic currents and background levels of harmonics voltages would require a very sophisticated system. The development of that system was beyond the scope of this project.
- By using state estimation, the utility can incorporate limited transmission-level monitoring with short-circuit simulations to produce accurate results for the entire transmission system. Transmission-level state estimation software is still in the embryonic stage, but the researchers believe that this type of system will be commercially available within the next few years. Once developed, the state estimation software will allow utilities to monitor approximately 10% of the transmission-system busses to predict power quality levels and performance indices over the entire system with a great degree of accuracy.

Target:

Power Quality for Improved Energy Delivery and Distribution

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