Security, Quality, Reliability, and Availability: Metrics Definition: Progress Report

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PRODUCT DESCRIPTION

This is a progress report that describes the four separate elements of SQRA, that is, security, quality, reliability, and availability as each pertains to electric power system performance. It addresses the attributes, related terminology, and indices that have evolved for measuring power system performance in these four areas. The report will assist the reader to understand the background and common usage of these individual elements of power system performance. It will also set the stage for evaluating how these individual element metrics might be combined as more strategic measures of power system performance.

Results & Findings

Current practices for evaluation of a power system have evolved more or less independently in several distinct performance areas such as distribution customer outage reporting, grid operating contingencies, monitoring of power quality variations, and measurement of transmission reliability. The way each of these performance elements have been applied depended on the area of interest in the power system analyzed; end use, distribution, transmission, or generation. And utility industry performance measurement practices and standards have evolved via groups that represented the interests in these different system areas from generation to end use. This report shows the characteristics of current performance measurement practices and the results can be used in developing new metrics that aim to integrate all the key concepts for a better measure of strategic SQRA.

Challenges & Objectives

Today's accepted industry practice for power system performance measurements is the starting point for introducing new and more integrated performance metrics. The challenge is to bridge between different performance metrics that are used at different levels of the power system. In some cases these metrics conflict with each other to the extent that improving performance in one area may detract from others. One objective of this report is to capture the elements of SQRA as applied in transmission and distribution systems. A further objective is to work through differences in requirements from power generation to end use, and to introduce a more integrated performance metrics. This process will require involvement of utility decision makers in order to set the strategic objectives that will drive how power system performance is to be evaluated in the future.

Applications, Values & Use

The strategic management of security, quality, reliability, and availability (SQRA) performance will improve tools, resources, and insights for utility decision makers. Applying more integrated measures of performance will prepare utility managers to cope with changes in the marketplace as well as the regulatory environment. When completed, this work will develop a strategic framework for understanding the value for improving electric power delivery to business enterprises. Protecting this interface between electricity and business requires a broad strategy. It will consider all elements of the power delivery and end-use process-from the power plant, to the interconnecting systems, to the response of the digital systems, processes, and businesses.

EPRI Perspective

Recent power outages and subsequent actions of the North American Electric Reliability Council (NERC) and regulators such as the Federal Energy Regulatory Commission (FERC) and state agencies have renewed awareness of the strategic importance of SQRA. In 2004, EPRI engaged the electric power industry in a new program to begin addressing important questions such as how to define security, how to benchmark it, and how can executives get the technical resources they need to strategically and effectively manage all elements of SQRA. Answering these questions will require new power system performance models that account for all the factors that affect powering delivery and end-use equipment. Not only does power quality and power continuity need to be considered but also the related security of supply needs to be addressed – that is, the probability that power continuity and quality will be maintained in the future. This report on the SQRA performance elements is a necessary step to refining and developing new metrics that will help to maximize the value of the electric power supply system.

Approach

The report identifies terminology from various sources and several different applications; and, the context of performance metrics related to the electric power system performance is also discussed. In particular, current industry practices and accepted standards for performance are considered as a first step toward developing metrics for SQRA. The approach in this document is to describe the general concepts followed by individual chapters that describe each element of SQRA. This includes the source and the context where the terminology has been used. In some cases recommended SQRA metric definitions are proposed.

Keywords

SQRA
Power systems indices
Outage reporting
Reliability
Power quality
Security
Availability
Power interruptions

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EXECUTIVE SUMMARY

Recent power outages and subsequent actions of the North American Electric Reliability Council (NERC) and regulators such as the Federal Energy Regulatory Commission (FERC) and state agencies have pointed out the strategic importance of power system performance. With the above in mind, EPRI has proposed development and application of a combined Security, Quality, Reliability, and Availability (SQRA)[1] measurement/metric system for overall power system performance. The SQRA-based metrics and their potential to evolve into future 'standardized' indices will apply all the way from the point of generation of electric power to its end use. That is, beyond the electric service entrance to the connecting pins on a semiconductor in an electronic appliance. In other words SQRA measures will likely guide utility strategic decisions and impact a wide variety of subsystems and delivery elements in the overall the power delivery system. SQRA measures will thus likely impact performance monitoring at the high voltage transmission system level and at low voltage distribution system and end-user equipment level.

Background

In 2004, EPRI engaged the electric power industry in a new program to begin addressing important questions such as how to define electric service performance, how to benchmark it, and how executives can get the resources they need to strategically and effectively manage all elements of SQRA. Answering these questions will require new power system performance models that take into account all the factors that affect powering end-use equipment. For transmission and generation systems especially, the traditional measures of continuity are inadequate to characterize the risk of system disruptions. For these systems, security of supply – that is, the probability that continuity and quality will be maintained in the future – must also be considered.

Terminology of electric power system performance is part of a larger effort to define metrics for SQRA relative to both the transmission and distribution systems. Strategic SQRA will also define the relationship of security to quality, reliability, and availability. Identifying and codifying the definition of security and other aspects of SQRA is absolutely essential for its strategic management. With this information, strategic and financial decisions to improve the overall power delivery system can be based on knowledge and available data, rather than mere anecdote and/or "expert" opinions.

This project's objectives are to develop the basis and guidelines for development of measurement metrics for each of the SQRA elements at the Transmission and at the Distribution

[1] Analysis of Extremely Reliable Power Delivery Systems, Technical Report Reference 1007281, EPRI CEIDS, Palo Alto, CA, April 2002.

Level, and begin development of the metrics themselves. Results will include what these metrics are without “security” in mind and what these metrics should be with “security” in mind. Activities used to develop the results of this project include:

- Surveys of industry key players
- Literature reviews and the application of existing standards
- Analysis and re-analysis of previous and on-going EPRI research
- Consultation with industry experts

A necessary first step is to identify the terminology used for SQRA in the context of electric power system performance. Currently many related terms have evolved over time and are applied differently among different organizations, and within different and/or alternative technical contexts. Some revisiting and harmonization of terms is needed to communicate the unique objectives of strategic SQRA compared to other important activities. This document is a progress report in the EPRI SQRA Program 121. It is intended to present the first efforts to align on the terminology of the four elements of SQRA and to suggest the definitions that are most relevant for describing strategic SQRA.

Typical Power Delivery Performance

The electrical transmission and distribution system, situated between central generation and the end-use customer, is often described as the utility power deliver system. The point of deliver is the user’s service entrance. This delivery system is the major factor in both power quality and reliability. Service entrance reliability has been measured based on the number and duration of outages caused and/or attributed to the local utility. Service entrance quality is measured primarily by variations in voltage characteristics; however, today, such voltage variations and other power quality indices are not monitored continuously and/or accurately at all customer locations, however, they are monitored well at some customer sites.

A number of different indices have been developed, and are generally accepted in the electric industry, for measuring and predicting service reliability. Until recently these indices only measured outages that last more than five minutes. A typical reliability assessment for a specific location is given in the total minutes of outage per year, or as the availability, which is 100% minus the percent of time that service is out. Since total outage time on average is only 100 to 200 minutes per year, unavailability is .00X and availability is 99.99X.

In the last few years some new indices have been added to the set of reliability definitions developed by IEEE 1366[2] to characterize momentary events in the electric supply. These are important to end-user process availability because very brief interruption, or voltage variations (voltage sags), may cause hours of process downtime. Indices for voltage sags are in the process of being developed by IEEE 1564 Working Group.

[2] Trial-Use Guide for Electric Power Distribution Reliability Indices, IEEE Standard 1366-2003, IEEE NY, NY

The realities of electric power generation, transmission, and distribution in the United States show that an average utility customer will experience several types of power disruptions in any particular year—including voltage sags, interruptions, transients, and other phenomena. In the past 10-15 years significant efforts have been expended to understand the level of electric service quality, continuity, and reliability delivered to users of electric power—much of this work conducted by utility companies themselves. Monitoring data, site investigations and case histories have documented occasional end use equipment and electric power compatibility problems in all business sectors and electric system types.

Experience and field data have shown that the single most frequent cause of end user PQ problems is low voltage or voltage sags. As shown in Figure 1-1, a single fault in the transmission or distribution system can affect voltage for miles around, and, depending on the location and severity, can impact hundreds or thousands of end users. Severity of voltage sags is measured by the minimum voltage during the voltage sag (sag magnitude) and the time the voltage is outside normal limits (sag duration), as illustrated in the graphic below. Measuring the duration and magnitude helps to predict if end-use equipment will be disrupted. The typical number of disruptive voltage sag events (voltage sags with a minimum voltage below 70% are often disruptive to industrial processes) occurring annually at any one location in the US is more than 10.

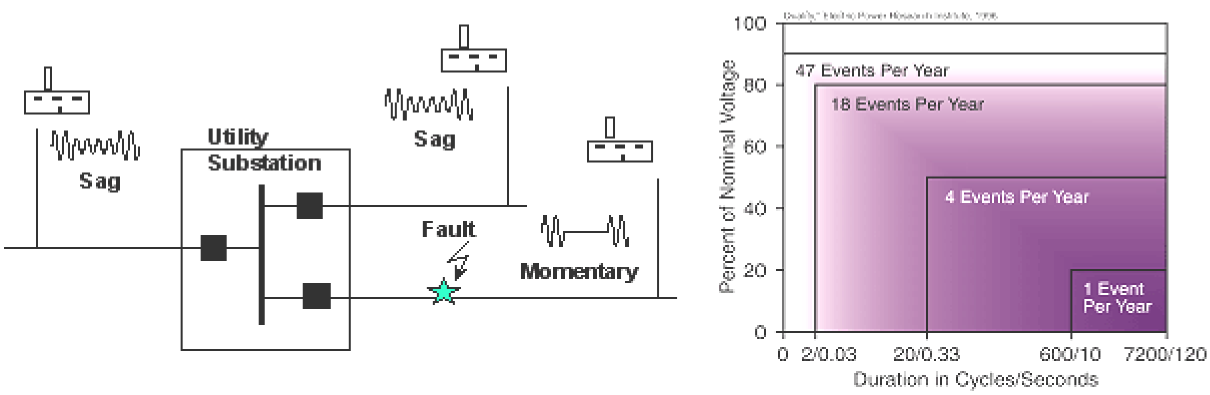

Figure 1-1
Fault Events in Power Systems Impact Voltage in the Vicinity, and These Events are the Most Common Cause of Power-Related End-User Equipment Disturbances

Although power system exposure to faults has not changed significantly over time, the proliferation of microprocessors and power electronics in commercial and industrial facilities has greatly increased the economic consequences of these power disturbance events. Most business enterprises count losses based on disruption of operations or process interruption time. In contrast, utility reliability indices are measures of the number and duration of power interruptions lasting more than five minutes even though the great majority of events affecting customers are not included in this category. The most common indices being used only consider power interruption and the number of customers interrupted. Consequently these indices are not a good measure of equipment downtime or the utility power interruption impact on business enterprises.

The location of faults in the power system is also a key factor is estimating impact. Statistics show that transmission faults occur less often than distribution faults, however, they are likely to impact more end users. Also, the transmission faults seldom result in an outage so they are usually not even counted when evaluating system performance. If faults are down stream of a recloser device in the power distribution system, then only the down stream customers are likely to experience a power interruption. If the fault is upstream, then a larger area and a larger number of customers will be affected. As shown in Figure 1-2, the trend is clear, i.e., as the power disturbance moves further up into the power system, more customers are affected. An event further downstream affects fewer customers but occurs more often because this type of event will generally have more exposure to disruption and include building wiring and other end use equipment problems.

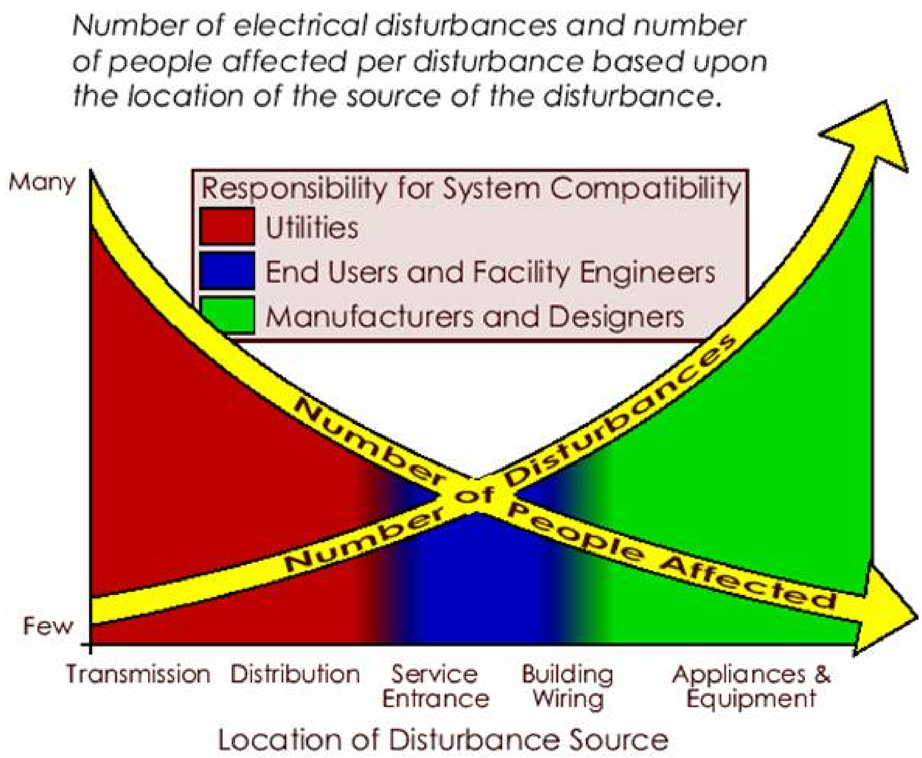

Figure 1-2
Relationship Power Disturbances and the Number of People Affected Depends on the Location of the Disturbance Source.

Another issue with current reliability measures is the difficulty in applying them to a specific location or case. Most indices are rough measures of average reliability over a large area. On the other hand specific feeder data may be highly variable and does not provide a good indication of future performance. Because of this, reliability assessment and evaluation methods based on probability theory are finding wider application today because they provide a quantitative prediction for future performance. Such methods also permit consistent, defensible, and unbiased assessments of system reliability that are not otherwise possible.

Evolution of Utility Industry Reliability Reporting

Data on outage occurrences of transmission facilities have been collected for many years, beginning in the 1940s and 1950s. Initially, reporting was limited to the frequency of outage occurrence on transmission lines. Early efforts did not generally collect data on outage duration, except to classify outages as temporary or permanent according to type of system restoration applied. Outage frequencies were classified into several general cause categories, but there were no formal definitions for different types of events and the statistics reported were limited to those contained in individual utility data forms and instructions. Statistics on operations, such as the number of substation breaker or recloser operations, were collected and recorded manually.

In the 1960's, methods were first proposed for calculating reliability of transmission and distribution "systems" (networks) in terms of the reliability of their individual "components." This followed the reliability calculation methods used in other electric circuits, in particular critical military systems, where data on component failure characteristics was being collected. The calculation method led to the need for more formal definitions of terms to foster uniformity and standardization of language among engineers engaged in reporting, analyzing, and predicting outages of transmission and distribution facilities and interruptions to customers. This resulted in development of one of the first power industry reliability standards, IEEE Std 346-1973[3].

In the 1980's, with the advent more digital processes and systems, more emphasis was placed on reliability measures and reporting. There was a need to include definitions for a broader scope of outage events. For example, two general categories of facilities (reportable entities) must be recognized to support presently available models. In one type of model, a transmission system is partitioned functionally into "units" which represent the capability to transfer power between specified points. In the second type of model, a system is partitioned physically into "components" to better estimate failure rates and contingencies.

Another development during this period was the importance of "related outage occurrences" and the need for redundancy. It was recognized that outage occurrences of two or more facilities are often related due to the physical construction of equipment (such as common structure), the electrical interconnection of equipment (common bus, for example), or exposure to a common environment (storms). Achieving clear and unambiguous definitions for related outage occurrences was important for reporting outages at the transmission unit level. At the component level, an important consideration was recognition of several different modes of failure, particularly for switching, protection, and automatic reclosing equipment.

These developments lead to creation IEEE Std 859, which provided standard terms for reporting and analyzing outage occurrences and outage states of electrical transmission facilities. The standard defined equipment component, unit, and terminal classifications. It described the states and events that ultimately determined reliability, and the time and exposure parameters that better defined the nature of outages. From these definitions several outage indices were

[3] IEEE Standard Definitions in Power Operations Terminology Including Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service, , IEEE Std 346-1973.

developed. However, no attempt was made to recommend acceptable equipment reliability levels.

When completed in 1987, IEEE Std 859 replaced the Std 346-1973. However, terms related to distribution system facilities and interruptions were eliminated from the scope of the new document. This opened the way for a separate effort to define reliability more in terms of the affect on distribution-connected end users rather than measures of component and unit reliability in the transmission system. And work continued through the 1990's on a new industry standard for measuring power system performance at the distribution level. It was introduced in 1998 as IEEE Std. 1366, a Trial Use Guide for Electric Power Reliability Indices.

The purpose of this guide was twofold. First, it presented a set of terms and definitions which could be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities. Secondly, it provided guidance for new personnel in the reliability area as well as tools for internal and external comparisons. This guide references both the IEEE Std 859 terms for transmission outage reporting, and IEEE Std 493, recommended practice for reliability in industrial and commercial facilities.

So the status of power industry reliability reporting practice today is to have different standards for different parts of the power system. IEEE 859-1987 (reaffirmed as a standard in 2002) is for Transmission. IEEE 1366-2001 (approved as a Guide in 2001) is for distribution. IEEE 762-1987 (reaffirmed as a standard in 2002) is for generation units. And IEEE 493-1997 is a recommended practice for design of reliable industrial and commercial power systems.

Reliability

Power system reliability is the over arching objective of SQRA. It encompasses the time an electric system is available, the frequency of failures, the various type of failures, and contingencies that define operating margins or when single component failures may result in system failures. The definition of a failure and the probability that a failure will occur are both key aspects of reliability.

One commonly accepted view on what system reliability should include is everything that may serve to reduce the probability that a failure will occur. Along the same line, high reliability should increase a power system's availability and reduce the number of failure events. However, these two measures are not necessarily improved in equal portions. For example, specific actions may significantly reduce the number of failures, while long repair times for remaining failure events still result in poor system availability.

In the context of SQRA we attempt to include the quality requirements of end-use equipment in defining power system reliability. So failures may be measured in equipment or process upsets and the restoration time may be how long it takes to restart the process irrespective of when power is restored. One challenge for today's electric power system is that the definition of a failure is expanding for many high- tech end-user equipment and processes. And some power-quality related failure modes are impacting the customer's perception of power system reliability. One of the more common examples of this impact is when sensitive industrial and data processes fail due to very brief voltage interruptions or voltage quality problems. Similarly, power system security issues may increase the probability of a failure.

Availability

As applied in electric power systems, the term availability simply means how much of the total time of interest the power is available. Availability is usually stated as a percentage. For example, a power system that is down for a total of 60 minutes each year would be said to be 99.98% availability. If the same power system failed 3 times in that year, then the mean-time between-failures would be 4 months. Availability and reliability are closely related in that each is a measure of time (or percentage of time) that a process is up and running. Availability, however, is more dependent on the time after a process is interrupted and reliability includes the number of events that can cause process interruptions.

Availability for sensitive digital processes acknowledges that there is a difference over the course of a year between a single one-hour electric power interruption and sixty one-minute interruptions. Since both these scenarios have 60 minutes of cumulative outage, the calculation of power availability in both cases would be the same. However, the calculation of the process availability should consider the time required to affect repairs and get things up and running again. As a result very high power availability may have poor reliability because of the number of upsets and poor process availability, because of the cumulative time needed to restore the process after a large number of short time events.

Availability as a Measure of Reliability

In modern business today we often hear the metric Six-Sigma or 6 standard deviations from the mean as an important measure of process performance and quality. Many electric customers are striving for perfection in their business processes. The 6-sigma objective sets a target of 3.4 defects out of 1,000,000 results or opportunities. Higher sigma means fewer defects. And one of the most important concepts in achieving a high sigma success rate in a process is to reduce the process variance. Mathematically, variance is the square of standard deviation, so decreasing process variation reduces the number of defects and increases the process sigma.

In the power delivery industry availability, measured in terms of 9's, has become more or less an equivalent to the 6-sigma objective. And six-9's, or 99.9999%, of power available is often cited as an objective for mission critical facilities. As shown in Table 1-1 the number of 9's is also equated to a number of minutes off supply. In fact six-9's is actually better performance than 6-sigma since the deviation or failure rate is 1 part per million compared to 3.4 parts per million. The typical utility service in the US is approximately 99.95%, which equates to a sigma of about 4.8. By this measure, the reliability of power delivery in the US is very good.

Table 1-1
Relationship Between Number of Nines and "Minutes Off" Supply

The Standard of Nines	The Number of Nines	Minutes Off Supply
0.99	2 Nines	5256
0.999	3 Nines	525.6
0.9999	4 Nines	52.56
0.99999	5 Nines	5.256
0.999999	6 Nines	0.5256
0.9999999	7 Nines	0.05256
0.99999999	8 Nines	0.005256
0.999999999	9 Nines	0.000526

The difference between the desired power availability for a particular site and the available power service at that site is one way to define opportunities for power system improvement. For example, if the desired power availability is 5 nines and the typical service availability is 3 nines, then on-site generation or energy storage is expected to have reliability value.

Quality

Power quality (PQ) has proven to be a critical element of electric power delivery because many modern electrical devices and electronic equipment react to variations in quality. In particular, continuous processes, from factory assembly lines to data processing, are vulnerable to quality variations. Upsets in even the smallest, and usually the most sensitive, equipment or device often results in downtime of an entire process or facility. The process outage usually occurs long after power is back to normal and often when electric service availability and reliability are relatively good. PQ related process outages are much more common than outage related event. However, traditional power system performance indices do not account for power quality variations. This is one of the important challenges of designing and implementing a strategic SQRA program.

Considering power quality properly is done by taking a step beyond the traditional measures of power continuity or the availability of power. It is well known that both reliability and availability tend to focus on complete interruptions of power, power quality acknowledges that there are other characteristics of electric power supply that can impact the performance of sensitive digital systems. Examples of these include sags, spikes, or transients in supply voltage, as well as unbalanced voltages, poor electrical system grounding, and harmonics. Quality at the point of end-use is influenced not just by the power delivery systems, but also by local wiring and neighboring end-user equipment and vulnerability of the electric system to external exposures.

Power quality evaluations must also consider the fact that many power quality variations are a function of the interaction between customer loads and the supply system. For instance, system harmonic distortion is caused by distorted currents drawn by nonlinear loads interacting with the frequency response characteristics of the supply system. This means that power quality evaluations must include assessments of the impacts of end users and possibly the application of limits and standards at the PCC with end users.

Power Quality Impact on Process Reliability

A key concept of SQRA is connection between PQ and reliability from an end-user viewpoint. The electric utility transmission and distribution system is a complex network intended to deliver the most reliable power to the majority of customers. Because of the way the system is protected, momentary disturbances are common. Every time a thunderstorm occurs, a tree or animal comes in contact with the power conductors, or some other abnormal fault event occurs, a certain number of electricity customers will experience a momentary interruption in power while many other customers will experience a momentary voltage reduction, called “voltage sag.” This is simply a reduction in the voltage available from the power source while the fault current is flowing. As soon as the fault is cleared, the power goes back to normal. In the majority of cases, the entire event lasts less than a half second. Unfortunately for most customer process equipment, it doesn’t matter because production has already stopped and a costly reset and or cleanup effort must be initiated.

In terms of utility power-system performance, everything has worked as intended and hopefully power is now back for all customers. Therefore, from a reliability standpoint (that is, long-term interruption), no one was interrupted for an extended period of time. This is good for the reliability indices that the electric utility reports annually, but is terrible from a customer standpoint because there may be literally millions of dollars in losses if this event upsets process operations for a group of manufacturing or production facilities.

Typically, the motors, pumps, compressors, and other mission-critical process equipment are not sensitive to the momentary voltage sags, but the control circuitry is extremely sensitive and causes the production equipment to trip offline. Even if the power-system fault is many miles away, a few of the more sensitive process controls systems will trip while others may be unaffected. If the fault is within a few miles of the substation bus, the resulting sag will be more severe and everything in the plant is likely to trip offline. The bad news is that each event can cause costly process downtime.

Security

The role of security in power system performance has not yet evolved into any consistent set of definitions or measurement methods. However, events that have occurred in recent years elevated the visibility and perceived importance of security in power system operations and protection of the electric infrastructure. Some of the complexities involved in protecting power systems and related infrastructures were identified by the *Electricity Infrastructure Security Assessment*, developed by EPRI in response to the 9-11 terrorist attacks. In particular, this assessment identified three different kinds of threats that need to be considered:

- Attacks *upon* the power system. In this case, the electricity infrastructure itself is the primary target -- with ripple effects, in terms of outages, extending into the customer base.

- Attacks *by* the power system**.** Here the ultimate target is the population, using parts of the electricity infrastructure as a weapon. Power plant cooling towers, for example, could be used to disperse chemical or biological agents.
- Attacks *through* the power system. Utility networks include multiple conduits for attacks on other infrastructures, including lines, underground cables and tunnels. An electromagnetic pulse, for example, could be coupled through the grid to damage both electricity and telecommunications networks.

In looking at future needs of the electric industry, system security was identified as one of the top few "difficult challenges" for utility system operations. Indeed, if infrastructure security is not assured, even maintaining current levels of productivity and service will be jeopardized. Conversely deploying some of the advanced technologies needed to enhance security will also have a positive effect on efforts to improve grid reliability and coordinate power system operations with those of other energy infrastructures. The strategic SQRA program aims to develop metrics that will allow utilities to measure security readiness and to make decisions on priorities and investments in this area.

Findings and Results

Current practices for evaluation of the electric power delivery system have evolved more or less independently in several distinct performance areas. For example customer outage reporting, distribution power quality, transmission grid reliability and operating contingencies, all use different performance metrics. Also performance metrics tend to vary depending on the operating level of interest, that is, at the point of end use, in the distribution, transmission network, or at the generator. And utility industry performance standards and related measurement practices have evolved around the interests of stakeholders at different levels in the power system, from generation to end-use.

This report has surveyed current performance measurement practices in the electric power industry. Several specific parameters were found as key to the performance in each of the strategic elements of SQRA. These parameters are summarized for each element:

- Security –should incorporate measures of both physical and cyber security. Under physical security, lines of communication and critical facilities or equipment need to be considered to the degree that they can affect the delivery of electric energy.
- Quality – Measurement parameters have been established for voltage sag, magnitude and duration, acceptable harmonic distortion, flicker, and unbalance levels. Both steady state conditions and momentary events need to be considered when measuring quality.
- Reliability – Measurement parameters need to include frequency of interruptions, time between interruptions, total duration or restoration time, and the number of end users affected. A simpler way to state this is the number, duration, and severity of outage events.
- Availability – Measurement parameters for availability have been established as the operating, or uptime, which is stated as a percent of total time of interest.

Given utility industry deregulation and the related unbundling of the system functions, the trend has been to separate power system performance into its various parts, generation, T&D and end-use. Nevertheless, once all the switches are closed it is one system and many of its component parts interact and combine in determining overall power delivery reliability. Understanding the key performance parameters for SQRA will help in the development of new metrics that better integrate all the related parts and add up to improved performance at the point of end-use. This progress report will assist the reader to understand the background and common usage of these individual elements of power delivery system performance. It will also set the stage for evaluating how these individual element metrics might be combined in more strategic measures of power delivery system performance in the future.

2 INTRODUCTION

Recent power outages and subsequent actions of the North American Electric Reliability Council (NERC) and regulators such as the Federal Energy Regulatory Commission (FERC) and state agencies have pointed out the strategic importance of power system performance. EPRI has proposed development and application of a combined Security, Quality, Reliability, and Availability (SQRA)[4] measure for overall power system performance. This metric and the potential for future indices are intended to apply all the way from the point of generation of electric power to the connecting pins on a semiconductor in electronic equipment at the point of end use. In other words SQRA measures will guide utility strategic decisions to consider the power system performance as it affects end-user processes.

In 2004, EPRI engaged the electric power industry in a new program to begin addressing important questions such as how to define electric service performance, how to benchmark it, and how can executives get the resources they need to strategically and effectively manage all elements of SQRA. Answering these questions will require new power system performance models that take in account all the factors that affect powering end-use equipment. Not only do power quality and continuity need to be considered but also the related security of supply – that is, the probability that continuity and quality will be maintained in the future.

Terminology of electric power system performance is part of a larger effort to define metrics for SQRA relative to both the transmission and distribution systems. Strategic SQRA will also define the relationship of security to quality, reliability, and availability. Identifying and codifying the definition of security and other aspects of SQRA is absolutely essential for its strategic management. With this information, strategic and financial decisions to improve the overall power delivery system (all the way to the consumer and end-use device) can be based on knowledge and available data, rather than mere anecdote and/or “expert” opinions.

The project objectives are to develop the basis and guidelines for development of measurement metrics for each of the SQRA elements at the Transmission and at the Distribution Level, and begin development of the metrics themselves. Results will include what these metrics are without “security” in mind and what these metrics should be with “security” in mind. The scope includes context and examples for discussing and examining electric power SQRA in terms of metrics appropriate to both the transmission and distribution systems. Other activities used to develop the results of this project include:

- Surveys of industry key players

[4] Analysis of Extremely Reliable Power Delivery Systems, Technical Report Reference 1007281, EPRI CEIDS, Palo Alto, CA, April 2002.

- Literature reviews
- Analysis and re-analysis of previous and on-going EPRI research
- Consultation with industry experts

A necessary step first step is to identify the terminology used for SQRA in the context of electric power system performance. Currently many related terms have evolved over time and are applied differently among different organizations, and within different and/or alternative technical contexts. Some revisiting and harmonization of terms is needed to communicate the unique objectives of strategic SQRA compared to other important activities. This document is a progress report in the EPRI SQRA Program 121. It is intended to present the terminology of the four elements of SQRA and to suggest the definitions that are most relevant for describing strategic SQRA.

Background

Electronic data communication, data processing, factory automation, and continuous process controls are all changing the power needs of commercial and industrial business enterprises. In many cases a new electricity customer class is emerging, where reliability and availability of power are of paramount importance. On-site generation, power conditioning, and energy storage technologies may have the potential to satisfy both the energy and premium power needs of these new customer classes. In some cases local energy efficiencies may also be gained by capturing both heat and power outputs. Even renewable energy resources such as bio-gas and solar, can play a role in producing clean energy near the point of use.

The question of how to obtain the full value of electrical power system assets is of interest from the central power station to the point of electricity use. Power system components are often not fully utilized because of peaks and valleys in demand. Many generator and storage assets are standing-by to operate only when normal power is interrupted. However, these are not able to protect modern industrial processes and electronic commerce from momentary power quality problems. It is reasonable to believe that the power system of the future will have built in attributes that address quality and reliability at all levels from the central station and transmission to distribution and end use.

As distributed energy options increase, and costs decline, it is likely that more on-site power technologies will be employed for mitigation of power quality and reliability problems. Also we expect that future advances in communication and control will enable these on-site energy technologies to be better integrated and provide benefits back to the grid, such as stabilizing voltage and following load demand. The problem at hand is to properly evaluate and effectively apply new power technologies in power system design.

Typical Power Delivery Performance

The electrical transmission and distribution system, situated between central generation and the end-use, is often described as the utility power deliver system. The point of deliver is the user’s service entrance. This delivery system is a major factor in both power quality and reliability Service entrance reliability has been measured based on the number and duration of outages caused and/or attributed to the local utility. Service entrance quality is measured primarily by variations in voltage however power quality is not monitored at most locations.

A number of different indices have been developed, and are generally accepted in the electric industry, for measuring and predicting service reliability. Until recently these indices only measured outages that last more than five minutes. A typical reliability assessment for a specific location is given in the total minutes of outage per year, or as the availability, which is 100% minus the percent of time that service is out. Since total outage time on average is only 100 to 200 minutes per year, unavailability is .00X and availability is 99.99X.

In the last few years some new indices have been added via an IEEE standard for utility system indices[5] that measure momentary events in the electric supply. These are important to end-user process availability because very brief interruption or voltage variations (voltage sags) may cause hours of process downtime. So far only brief interruptions are included in standard indices. This is one problem with current indices, which this SQRA effort will address.

The realities of electric power generation, transmission, and distribution in the United States show that an average utility customer will experience several types of power disruptions in any particular year—including voltage sags, interruptions, transients, and other phenomena. In the past 10-15 years significant efforts have been expended to understand the level of electric service quality, continuity, and reliability delivered to users of electric power—much of this work conducted by utility companies themselves. Monitoring data, site investigations and case histories have documented occasional end use equipment and electric power compatibility problems in all business sectors and electric system types.

Experience and field data have shown that the single most potent cause of end user PQ problems is low voltage or voltage sags. As shown in Figure 2-1, a single fault in the transmission or

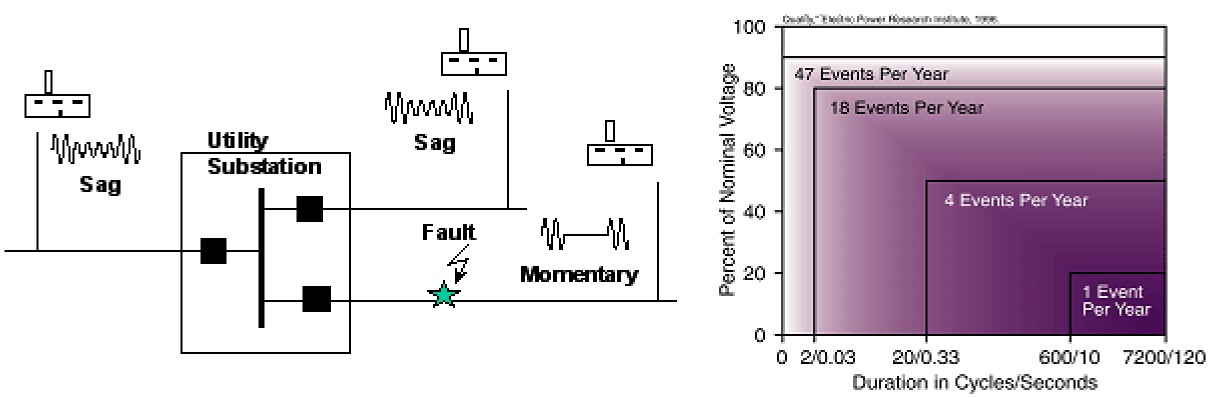

Figure 2-1
Fault Events in Power Systems Impact Voltage in the Vicinity and These Events are the Most Common Cause of Power-Related End-User Equipment Disturbances

[5] Trial-Use Guide for Electric Power Distribution Reliability Indices, IEEE Standard 1366-2003, IEEE NY, NY

distribution system can affect voltage for miles around, and, depending on the location and severity, can impact hundreds or thousands of end users. Severity of voltage sags is measured by the percent loss of voltage (sag magnitude) and the time the voltage is outside normal limits (sag duration) as illustrated in the graphic below. Measuring the duration and magnitude helps to predict if end-use equipment will be disrupted. The typical number of disruptive voltage sag events (e.g. voltage sags with a minimum voltage below 70%) occurring annually at any one location in the US is more than 10.

Although power system exposure to faults has not changed significantly over time, the proliferation of microprocessors and power electronics in commercial and industrial facilities has greatly increased the economic consequences of these power disturbance events. Most business enterprises count there losses based on disruption of operations or process interruption time. In contrast, utility reliability indices are measures of the number and duration of power interruptions without regard for very brief voltage variations that may result in much longer end use disruptions and process downtimes. The most common indices being used only consider power interruption and the number of customers interrupted. Consequently these indices are not a good measure of equipment downtime or the utility power interruption impact on business enterprises.

The location of faults in the power system is also a key factor is estimating impact. Statistics show that transmission faults occur less often than distribution faults, however, they are likely to impact more end users. If faults are down stream of a recloser device in the power distribution system, then only the down stream customers are likely to experience a power interruption. If the fault is upstream, then a larger area and a larger number of customers will be affected. As shown in Figure 1-2, the trend is clear, i.e., as the power disturbance moves further up into the power system, more customers are affected. An event further downstream affects fewer customers but occurs more often because this type of event will generally have more exposure to disruption and include building wiring and other end use equipment problems.

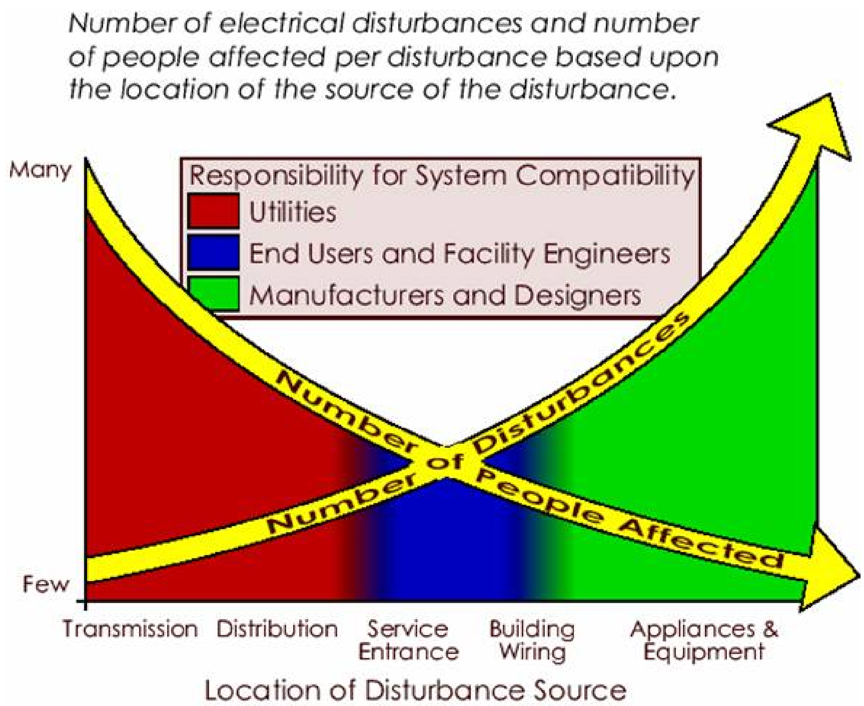

Figure 2-2
Relationship Power Disturbances and the Number of People Affected Depends on the Location of the Disturbance Source.

Another issue with current reliability measures is the difficult in applying them to a specific location or case. Most indices are rough measures of average reliability over a large area. On the other hand specific feeder data may be highly variable and does not provide a good indication of future performance. Because of this, reliability assessment and evaluation methods based on probability theory are finding wider application today because they provide a quantitative prediction for future performance. Such methods also permit consistent, defensible, and unbiased assessments of system reliability that are not otherwise possible.

Conventional Measures of Reliability

The term reliability in the context of electric power systems is generally used to indicate the ability of a system to continue to perform its intended function. In its simplest form we consider that power is either available or not. At the transmission level the power system is connected as a network and power flows can usually follow several different paths. Consequently load-related indices are not well defined. At the distribution level most of the power system is in a redial configuration suitable for load related indices. And the classic measurement indices that have proven to be most accepted and meaningful in power distribution system analysis such as from Billinton[6] and Patton[7], are:

6 Billinton, R., and Allan, R. N., "Reliability Evaluation of Power Systems," Plenum Publishing Corp., 1983.

- Load interruption frequency (number/unit time)
- Expected duration of load interruption events (time)

These indexes can be computed and then used to compute other indexes that are useful:

- Total expected (average) interruption time per year (or other time period)
- System availability or unavailability as measured at the load supply point in question
- Expected demand, but unsupplied, energy per year

These measures become more complicated when different degrees of performance and failure are considered. The disruptive effect of power interruptions is often not linear in relation to number of phases effected and duration of the interruption. Thus, it is often desirable to compute not only an overall interruption frequency but also frequencies of interruptions categorized by the appropriate durations. This is particularly important in cases where no interruption occurs and the issue depends on the process tolerance for varying degrees of distortion, different effects of unbalance, sags or swells. Thus the SQRA measurement needs to consider all of these factors.

Power Quality Vs Reliability

A key to the application of SQRA is the connection between PQ and reliability from an end-user viewpoint. The electric utility transmission and distribution system is a complex network intended to deliver the most reliable power to the majority of customers. Because of the way the system is protected, momentary disturbances are a common event.

Every time a thunderstorm occurs, a tree or animal comes in contact with the power conductors, or some other abnormal fault event occurs, a certain number of electricity customers will experience a momentary interruption in power while many other customers will experience a momentary voltage reduction called a “voltage sag.” The sag is simply a reduction in the voltage available on from the power source while the fault current is flowing. As soon as the fault is cleared, the power goes back to normal. In the majority of cases the entire event lasts less than a quarter second. Unfortunately for most customers’ process equipment, it doesn’t matter that the event is very short because production has already stopped, and a costly reset and or cleanup effort is underway.

In terms of utility power-system performance, everything has worked as intended and hopefully power is now back for all customers. Therefore, from a reliability standpoint (that is, long-term interruption), no one was interrupted. This is good for the reliability indices that the electric utility reports annually, but it is not good from a customer standpoint because there may experience thousands of dollars in losses if this event upsets process operations for a group of manufacturing or production facilities.

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7 Ayoub, A. K., and Patton, A. D., “A frequency and duration method for generating system reliability evaluation,” IEEE Transactions on Power Apparatus and Systems, Nov. Dec. 1976, pp. 1929–1933.

Typically, the motors, pumps, compressors, and other major process equipment are not sensitive to the momentary voltage sags, but the control circuitry of these processes may be extremely sensitive. This control sensitivity causes the production equipment to trip offline. Even if the power-system fault is many miles away, a few of the more sensitive process controls will trip while others may be unaffected. If the fault is within a few miles of the substation bus, the resulting sag will be more severe and everything in the plant is likely to trip offline. The bad news is that each event can cause costly process downtime.

Evolution of Utility Industry Reliability Reporting

Data on outage occurrences of transmission facilities have been collected for many years, beginning in the 1940s and 1950s. Initially, reporting was limited to the frequency of outage occurrence on transmission lines. Early efforts did not generally collect data on outage duration, except to classify outages as temporary or permanent according to type of system restoration applied. Outage frequencies were classified into several general cause categories, but there were no formal definitions for different types of events and the statistics reported were limited to those contained in individual utility data forms and instructions. Statistics on operations, such as the number of substation breaker or recloser operations, were collected and recorded manually.

In the 1960's, methods were first proposed for calculating reliability of transmission and distribution “systems” (networks) in terms of the reliability of their individual “components.” This followed the reliability calculation methods used in other electric circuits, in particular critical military systems, where data on component failure characteristics was being collected. The calculation method led to the need for more formal definitions of terms to foster uniformity and standardization of language among engineers engaged in reporting, analyzing, and predicting outages of transmission and distribution facilities and interruptions to customers. This resulted in development of one of the first power industry reliability standards, IEEE Std 346-1973[8].

In the 1980’s, with the advent more digital processes and systems, more emphasis was placed on reliability measures and reporting. There was a need to include definitions for a broader scope of outage events. For example, two general categories of facilities (reportable entities) must be recognized to support presently available models. In one type of model, a transmission system is partitioned functionally into “units” which represent the capability to transfer power between specified points. In the second type of model, a system is partitioned physically into “components” to better estimate failure rates and contingencies.

Another development during this period was the importance of “related outage occurrences” and the need for redundancy. It was recognized that outage occurrences of two or more facilities are often related due to the physical construction of equipment (such as common structure), the electrical interconnection of equipment (common bus, for example), or exposure to a common environment (storms). Achieving clear and unambiguous definitions for related outage occurrences was important for reporting outages at the transmission unit level. At the component

[8] IEEE Standard Definitions in Power Operations Terminology Including Terms for Reporting and Analyzing Outages of Electrical Transmission and Distribution Facilities and Interruptions to Customer Service, , IEEE Std 346-1973.

level, an important consideration was recognition of several different modes of failure, particularly for switching, protection, and automatic reclosing equipment.

These developments lead to creation IEEE Std 859, which provided standard terms for reporting and analyzing outage occurrences and outage states of electrical transmission facilities. The standard defined equipment component, unit, and terminal classifications. It described the states and events that ultimately determined reliability, and the time and exposure parameters that better defined the nature of outages. From these definitions several outage indices were developed. However, no attempt was made to recommend acceptable equipment reliability levels.

When completed in 1987, IEEE Std 859 replaced the Std 346-1973. However, terms related to distribution system facilities and interruptions were eliminated from the scope of the new document. This opened the way for a separate effort to define reliability more in terms of the affect on distribution-connected end users rather than measures of component and unit reliability in the transmission system. And work continued through the 1990's on a new industry standard for measuring power system performance at the distribution level. It was introduced in 1998 as IEEE Std. 1366, a Trial Use Guide for Electric Power Reliability Indices.

The purpose of this guide was twofold. First, it presented a set of terms and definitions which could be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities. Secondly, it provided guidance for new personnel in the reliability area as well as tools for internal and external comparisons. This guide references both the IEEE Std 859 terms for transmission outage reporting, and IEEE Std 493, recommended practice for reliability in industrial and commercial facilities.

So the status of power industry reliability reporting practice today is to have different standards for different parts of the power system. IEEE 859-1987 (reaffirmed as a standard in 2002) is for Transmission. IEEE 1366-2001 (approved as a Guide in 2001) is for distribution. IEEE 762-1987 (reaffirmed as a standard in 2002) is for generation units. And IEEE 493-1997 is a recommended practice for design of reliable industrial and commercial power systems.

How to Use This Document

This is a progress report that describes the four separate elements of SQRA, that is, security, quality, reliability, and availability as each pertains to electric power system performance. It addresses the attributes, related terminology, and any indices that have evolved for measuring power system performance in these four areas.

The report identifies terminology from various sources and several different applications and contexts related to the electric power system performance. These need to be considered when developing metrics for SQRA. The approach in this document is to describe the general concepts in the introduction, Chapter 2. This is followed by chapters that describe each element of SQRA in turn, including the source and the context where the terminology has been used. In some cases definitions to be used in the SQRA method are proposed. Chapters 3 thru 6 provide the current terminologies of Security, Quality, Reliability and Availability. These chapters will assist the reader to understand the background and common usage of these individual elements of power system performance. The report sets the stage for evaluating how these individual element metrics might be combined in more strategic measures of power system performance.

3
SECURITY

Some of the complexities involved in protecting power systems and related infrastructures were identified by the *Electricity Infrastructure Security Assessment*, developed by EPRI in response to the 9-11 terrorist attacks. In particular, this assessment identified three different kinds of threats that need to be considered:

- Attacks *upon* the power system. In this case, the electricity infrastructure itself is the primary target -- with ripple effects, in terms of outages, extending into the customer base.
- Attacks *by* the power system**.** Here the ultimate target is the population, using parts of the electricity infrastructure as a weapon. Power plant cooling towers, for example, could be used to disperse chemical or biological agents.
- Attacks *through* the power system. Utility networks include multiple conduits for attacks on other infrastructures, including lines, underground cables and tunnels. An electromagnetic pulse, for example, could be coupled through the grid to damage both electricity and telecommunications networks.

Attributes of Power System Security

In 2002 NERC published security guidelines for the electric sector[9]. These guidelines apply to critical facilities and operating assets. They provide one checklist and general description of power system security attributes.

EPRI Infrastructure Security Initiative

In looking at future needs of the electric industry, system security was identified as one of the top few “difficult challenges” for utility system operations. Indeed, if infrastructure security is not assured, even maintaining current levels of productivity and service will be jeopardized. Conversely deploying some of the advanced technologies needed to enhance security will also have a positive effect on efforts to improve grid reliability and coordinate power system operations with those of other energy infrastructures.

[9] “Security Guidelines for the Electricity Sector,” Version 1.0, North American Electric Reliability Council, June 14, 2002

Utilities participating in EPRI's Infrastructure Security Initiative identified five potentially high payback areas and proposed related research. These included:

- Develop Conceptual Designs for Recovery Transformers
- Create a Vulnerability Self Assessment Methodology
- Provide Measures to Enhance Secure Communications
- Conduct Mock "Red Team" Attacks
- Build a Check list of Judicious Actions ad Immediate Countermeasures

The **RECOVERY TRANSFORMER** can be a critical element in facilitating recovery of the U.S. electric grid after a terrorist attack is to have recovery transformers designed for rapid deployment and installation, based on storing such equipment at strategic U.S. locations. Transformers typically need to be customized for specific uses and take about 1.5 years to build, transport, and install. The research will develop conceptual designs for recovery transformers with multiple MVA ratings for connection at multiple voltages and sized to allow for transportation by rail, truck, and/or large cargo planes.

Utilities indicated that they needed a method to facilitate **VULNERABILITY ASSESSMENTS**. The overall goal of work in this area is to develop a vulnerability self assessment methodology capable of determining the impact of potential terrorist attacks anywhere in the electricity supply chain. During the planning a new procedure was developed to identify and rank critical simultaneous multi-station contingencies, which might be expected from a coordinated terrorist attack. Vulnerability self-assessment guidelines have been developed and published by EPRI[10]. These guidelines describe general approaches, considerations, practices, and planning philosophies to be applied in protecting the electric infrastructure systems.

SECURE COMMUNICATIONS and cyber security have become a major issue for electric utilities as they increasingly network their computer systems and power system controls and monitoring systems. Unauthorized penetration of utility communications systems has already occurred—and companies are likely to remain vulnerable—unless focused efforts are undertaken to make these systems more secure. Fortunately, there is a lot of related work on cyber security in the IT industry that can be applied to utility computer applications. Several efforts aimed specifically at utility industry communications have also been completed. In 2000 EPRI published a communication assessment procedure[11] and an information security primer[12].

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[10] Security Vulnerability Self-Assessment Guidelines for the Electric Power Industry, 1001639 Topical Report, EPRI Palo Alto, CA December 2002

[11] Communications Security Assessment for the United States Electric Infrastructure, 1001174, Final Report, EPRI Palo, Alto, CA December 2000

[12] Information Security Primer, Release 1.0, EPRI and Secure Computing Corporation, Copyrighted 2000.

Several reports have also been published by EPRI on inter-control center communications protocols (ICCP).

"RED TEAM" ATTACKS have been a proven way to demonstrate best practices for computer security. They probe for weaknesses in computer and information networks by launching mock assaults in a manner similar to the Federal Aviation Administration's "Red Team" effort. The key lessons learned from "Red Team" exercises at volunteer utilities included:

- Formation of an effective Incident Response Team at utilities represents an important way to assess and mitigate impacts of future cyber threats
- Numerous security "weak links" include remote locations and business partners tied to a utility's cyber network
- Periodic employee training is key to an effective security program Future work intends to conduct mock assaults on volunteer host utility systems directly through hardware (e.g., remote terminal units) or through communication systems (e.g., microwave links). This work would provide, for the first time, a realistic assessment of utility vulnerabilities from such communication systems.

IMMEDIATE COUNTERMEASURES were identified as a critical need after the August 14, 2003 Northeast outage. A number of prudent, "no-regrets" countermeasures need to be identified and implemented immediately in anticipation of a possible near-term terrorist attack on the U.S. electricity infrastructure. To meet this need, a fast-track project is proposed to develop a list of urgently recommended countermeasures, based on expert judgment and on the experiences of utilities (both domestic and international), which are recognized leaders in electric grid system security. The aim of this project is to provide industry professionals with a checklist of judicious actions to promptly undertake the impacts of near-term terrorist attacks and/or aid in the recovery from such terrorist attacks.

FERC Security Guidelines

The DOE has designated the North America Electric Reliability Council (NERC) as the Sector Coordinator for the Electricity Sector (ES). NERC, as the Sector Coordinator, has the responsibility to:

- assess sector vulnerabilities, develop a plan to reduce electric system vulnerabilities,
- propose a system for identifying and averting attacks,
- develop a plan to alert electricity sector participants and appropriate government agencies that an attack is imminent or in progress, and
- assist in reconstituting minimum essential electric system capabilities in the aftermath of an attack.

The idea of protecting the electric system infrastructure is not new. The electric grid is designed to ensure a reliable supply of electricity, even in the face of adverse conditions. Throughout its history, the industry has been able to restore service consistently and quickly after earthquakes, hurricanes, major floods, ice storms, and a variety of other natural and manmade disasters. Its experience in emergency management has prepared the industry to respond effectively to a "spectrum of threats" using its existing structure, resources, and plans. This spectrum ranges from simple trespassing, to vandalism, to civil disturbances, to dedicated acts of terror and sabotage. Perpetrators include "insiders" and "outsiders" whose actions may be cyber or physical in nature.

Security Guidelines for the Electricity Sector

Overview Version 1.0 June 14, 2002 North American Electric Reliability Council For purposes of these guidelines, a critical facility may be defined as any facility or combination of facilities, if severely damaged or destroyed, would have a significant impact on the ability to serve large quantities of customers for an extended period of time, would have a detrimental impact to the reliability or operability of the energy grid, or would cause significant risk to public health and safety. Each security guideline for the electricity sector is summarized below.

Companies may wish to review their plans, practices, and procedures for these elements:

- Vulnerability and Risk Assessment - Helps identify those facilities that may be critical to overall operations, as well as their vulnerabilities. Consideration should be given to closely safeguarding such information and restricting it to only a few individuals with a "need to know."
- Threat Response Capability - Ensures that company personnel at critical operating facilities understand how to respond to a spectrum of threats, both physical and cyber. Consideration should be given to NERC's "Threat Alert Levels and Response Guidelines."

Vulnerability and Risk Assessment

Helps identify those facilities that may be critical to overall operations, as well as their vulnerabilities. Consideration should be given to closely safeguarding such information and restricting it to only a few individuals with a "need to know."

Threat Response Capability

Ensures that company personnel at critical operating facilities understand how to respond to a spectrum of threats, both physical and cyber. Consideration should be given to NERC's "Threat Alert Levels and Response Guidelines."

Emergency Management

Ensures that companies are prepared to respond to a spectrum of threats, both physical and cyber. Consideration should be given to reviewing, revising, and testing emergency plans on a regular basis. Plans might include training provisions for key responders to ensure they have the skills and knowledge to effectively carry out those plans. Maintaining comprehensive mutual assistance agreements at the local, state and regional levels also supports response, repair, and restoration activities in the event a critical facility is disrupted. Liaison relationships with local FBI offices as well as with other local law enforcement agencies are also effective.

Continuity of Business Processes

Reduces the likelihood of prolonged interruptions and enhances prompt resumption of operations when interruptions occur. Consider flexible plans that address key areas such as telecommunications, information technology, customer service centers, facilities security, operations, generation, power delivery, customer remittance and payroll processes. It is useful to revise and test plans on a regular basis. It also is advisable to train personnel so they fully understand their roles with respect to the plans.

Communications

Ensures the effectiveness of threat response, emergency management, and business continuity plans. Consideration should be given to establishing liaison relationships with federal, state, county, and local law enforcement agencies in the area. Building the relationship might include providing tours of critical facilities for law enforcement agencies having jurisdiction in areas where those facilities are located, and planning to identify possible response needs. Such liaisons may need to be periodically updated and tested. Consideration also should be given to planning how personnel will respond to alarms, outages, or other issues at critical operating facilities. Robust communications systems such as radio, cellular phone, or similar communications devices are effective. Company the facility or asset owner, operator, etc.

Critical Asset

Those facilities, systems, and equipment which would, if destroyed, degraded, or rendered unavailable, negatively impact the regional, national, or North American electric grid reliability and financial stability. Intruder any unauthorized individual or any individual performing unauthorized activity within the substation. Physical Security Perimeter A type of gate, door, wall, or fence system that is intended to restrict and control the physical access or egress of personnel Security Assets Fences, gates, alarm systems, guards, and other security elements that can individually or as a system be applied to critical electrical assets to maintain reliability or reduce risk. Substation Secure Area The area contained within the first or outer substation physical security perimeter

Physical Security

Mitigates the threat from inside and outside the organization. A Physical Security Program might include deterrence and prevention strategies. A systems approach is advisable, where detection, assessment, communication, procedures, and resources.

Information Technology/Cyber Security

Mitigates the threat from inside and outside the organization. Consideration should be given to computer network monitoring and intrusion detection, placing particular attention on EMS, SCADA, or other key operating systems. It is advisable that only authorized persons have access to those critical systems, adequate firewall protection and periodic audits of the network and existing security protocols. Third-party penetration testing may be useful.

Employment Screening

Mitigates the threat from inside the organization. Hiring standards and pre employment and reliability of personnel who have unescorted access to critical facilities, including contractors and vendors.

Protecting Potentially Sensitive Information

Reduces the likelihood that information could be used by those intending to damage critical facilities, disrupt operations, or harm individuals. Consider creating a hierarchical confidentiality classification framework (e.g. Public, Market Participant Confidential, Company Confidential, Highly Confidential) and the authorization requirements and conditions to permit disclosure.

Security Terminology

The following alphabetical listing of terms comes from several sources as indicated at the end of each definition. This listing is intended as a starting point for defining relevant term for utility infrastructure security applications. Relative to other areas such as reliability or quality, there are few industry practices documents or standards to draw from in the area of security. Consequently this is not a complete list, but a work in progress. Additional tasks to be completed in the EPRI strategic SQRA program are expected to provide additional terms and definitions.

accountability

The security principle that all parties concerned with the security of information systems (owners, providers, users, and others) should have explicit responsibilities and accountability, from University of CA Berkeley, security glossary

active attack

Attacks which modify the target system or message, i.e. attacks which violate the integrity of the system or message are examples of an active attack. Another example in this category is an attack on the availability of a system or service, a so-called denial-of-service (DoS) attack, from University of CA Berkeley, security glossary

asset, critical

Those facilities, systems, and equipment which would, if destroyed, degraded, or rendered unavailable, negatively impact the regional, national, or North American electric grid reliability and financial stability, from NERC Security Guidelines, June 14, 2002

authentication

The process of proving that a person or other agent has been correctly identified, or that a message is received as transmitted. Authentication supports the principle of accountability. Methods of authentication can be based on: what you know, such as a logon password what you have, such as a key or card what you are; this includes various biometrics such as fingerprints, retina patterns, voice and face characteristics, from University of CA Berkeley, security glossary

confidentiality (also secrecy or privacy)

Preventing the disclosure of information to unauthorized persons or (especially network confidentiality) making it incomprehensible to an electronic eavesdropper, from University of CA Berkeley, security glossary

critical facility

Any facility or combination of facilities, if severely damaged or destroyed, would have a significant impact on the ability to serve large quantities of customers for an extended period of time, would have a detrimental impact to the reliability or operability of the energy grid, or would cause significant risk to public health and safety, from University of CA Berkeley, security glossary

electronic control and protection systems

Those systems used to regulate physical processes, including but not limited to: electronic protective relays, substation automation and control systems, power plant control systems, energy management systems (EMS), supervisory control and data acquisition (SCADA), programmable logic controllers (PLC). ECPS attributes include a Time Critical nature and automated response, from NERC Security Guidelines

electronic eavesdropping (also wiretapping or cable sniffing)

Monitoring network transmissions to gather information. This is a form of passive attack on data confidentiality and includes unauthorized interception of messages. Gathering unprotected passwords is often the primary reason for mounting an eavesdropping attack on a network, from University of CA Berkeley, security glossary

integrity

Integrity refers to aspects of the quality of information and systems. For example, integrity means that the data or message is not destroyed or corrupted, and that systems operate correctly, from University of CA Berkeley, security glossary

intruder

Any unauthorized individual or any individual performing unauthorized activity within the substation, from NERC Security Guidelines

passive attack

When confidentiality is violated but the state of the system is not affected, an attack is passive. An example is the electronic eavesdropping on network transmissions to release message contents or to gather unprotected passwords, from University of CA Berkeley, security glossary

physical security perimeter

A type of gate, door, wall, or fence system that is intended to restrict and control the physical access or egress of personnel. Security Assets Fences, gates, alarm systems, guards, and other security elements that can individually or as a system be applied to critical electrical assets to maintain reliability or reduce risk, from NERC Security Guidelines

remote access

Access to an ECPS by anything other than a directly connected operations system. Includes, for example, the functions of administration, diagnostics, configuration, non-operator observation, and non-routine or infrequent control. Includes, for example, applications such as telnet, SSH, and remote desktop software such as pcAnywhere™, Dameware™, VNC™. Currently available operating systems may natively include this type of functionality. Includes all private and public telecommunications links, for example, dial-up modem, frame relay, ISDN, public switched telephone network, leased line, microwave, fiber optic, Internet, wireless, from NERC Security Guidelines

time critical

Involves a specific bounded time window within which one or more specified actions must be completed with some defined level of certainty, from NERC Security Guidelines

Security Indices

At this time security indices have not been developed. Future indices on this topic are planned by EPRI, to incorporate measures of both physical and cyber security. Under physical security, lines of communication and critical facilities or equipment need to be addressed to the degree that they affect the delivery of electric energy.

4
QUALITY

Power quality (PQ) has proven to be a critical element of electric power delivery because many modern electrical devices and electronic equipment react to variations in quality. In particular continuous processes, from factory assembly lines to data processing, are vulnerable to quality variations. Upsets in even the smallest, and usually the most sensitive, equipment or device often results in downtime of an entire process or facility. The process outage usually occurs long after power is back to normal and often when electric service availability and reliability are relatively good. PQ related process outages are much more common than outage related events. However, traditional power system performance indices do not account for power quality variations. This is one of the important challenges of designing and implementing a strategic SQRA program.

Attributes of Power System Quality (from IEEE 1159)

Because of the growing interest power quality, attributes have been defined in significant detail over the last 10 years via several standards development activities within the IEEE[13]. Standards for power delivery, service, power conditioning equipment, and building wiring and grounding have been developed. For example, the "Recommended Practice on Monitoring Electric Power Quality," IEEE Std. 1159-1995 defines PQ attributes for monitoring. The purpose of this particular standard has been to define the attributes with enough detail so that monitoring results are meaningful, and facilitate better communications and understanding between customers, manufacturers, and utilities.

Table 4-1 summarizes these PQ attributes of voltage and frequency. These are divided into seven main categories of electromagnetic phenomena that occur in power systems and given descriptive names such as impulsive transient or momentary sag. For each phenomena the typical spectral content, duration and magnitude are provided.

[13] Power Quality Standards Update:2000, EPRI Palo Alto, CA, 1001252, December 2000.

Table 4-1
IEEE Std. 1159-1995 Categories and Typical Characteristics of Power Quality Attributes (Electromagnetic Phenomena in Power Systems)

Categories	Typical Spectral Content	Typical Duration	Typical Voltage Magnitude
1. Transients			
Impulsive			
Nanosecond	5 ns rise	< 50 ns	
Microsecond	1 ns rise	50 ns – 1 ms	
Millisecond	0.1 μs rise	> 1 ms	
Oscillatory			
Low frequency	< 5 kHz	0.3 – 50 ms	0 – 4 pu
Medium frequency	5 – 500 kHz	20 μs	0 – 8 pu
High frequency	0.5 – 5 MHz	5 μs	0 – 4 pu
2. Short Duration Variations			
Instantaneous			
Sag		0.5 – 30 cycles	0.1 – 0.9 pu
Swell		0.5 – 30 cycles	1.1 – 1.8 pu
Momentary			
Interruption		0.5 cycles – 3 s	< 0.1 pu
Sag		30 cycles – 3 s	0.1 – 0.9 pu
Swell		30 cycles – 3 s	1.1 – 1.4 pu
Temporary			
Interruption		3 s – 1 min	< 0.1 pu
Sag		3 s – 1 min	0.1 – 0.9 pu
Swell		3 s – 1 min	1.1 – 1.2 pu
3. Long Duration Variations			
Interruption, sustained		> 1 min	0.0 pu
Undervoltages		> 1 min	0.8 – 0.9 pu
Overvoltages		> 1 min	1.1 – 1.2 pu
4. Voltage Unbalance		**Steady state**	**0.5 – 2%**
5 .Waveform Distortion			
DC offset		Steady state	0 – 0.1%
Harmonics	0 – 100th H	Steady state	0 – 20 %
Interharmonics	0 – 6 kHz	Steady state	0 – 2%
Notching		Steady state	
Noise	Broad-band	Steady state	0 – 1%
6. Voltage Fluctuations	**< 25 Hz**	**intermittent**	**0.1 – 7%**
7. Power Frequency Variations		**< 10 s**	

The following provides an additional description of the main quality phenomena categories given in IEEE 1159. PQ attributes are best described using both main and sub-category names as shown in the table. For example, harmonic waveform distortion, temporary sag, or long duration undervoltage are all well-defined descriptions of phenomena with specified characteristics.

Transients (Voltages and Currents)

Transient voltages and currents are very short duration events, < 50 mS. They are usually a result of sudden changes in power systems and they are shaped by the systems response to the change. Besides major generator loss, the two main sources of network induced transient events are switching and lightning, where the sudden change is a connection, disconnection, or injection of voltage or current.

1. Connection or disconnection of elements on the power system. Capacitor switching, line switching, and load turn on or turn off, are all examples of these types of events.
2. Injection of energy into the power system. A lightning strike or electrostatic discharges are examples of this type of event.

The energy in these transients can contribute to the breakdown of components and/or insulation in residential electrical equipment such as appliance power supplies, compressor motors, and personal computing equipment. For the 120-Vrms system, the normal mode (line to line and line to neutral) magnitude of concern begins at about 500 volts peak or above. For other base voltage levels a similar peak ratio of four times the RMS value provides a good rule of thumb for approximating the level of concern.

Short-Duration Variations

Short-duration voltage variations include measurable RMS deviations such as voltage interruptions, sags, and swells that last between one-half cycle and one minute. The most common of these variations last less than a few seconds and are often the result of three conditions:

- A fault on the power system
- Loose connections in wiring
- The energizing of large loads such as large induction motors

Of the three conditions listed above, a fault on the power system and loose wiring connections are the most common conditions that result in a short duration voltage variations. Short-duration variations are generally defined by the number of electrical cycles that they last, and in the percent deviation from the nominal system voltage. These variations can cause electronic equipment and process equipment to shut down or to malfunction and section four details some of the positive impacts

Figure 4-1 shows the voltage waveform typically associated with a voltage sag (or dip) disturbance. Typically for transmission faults, these voltage disturbances last fractions of a second (≈ 1/10 second), which represents the total fault-clearing time for transmission faults. However, these momentary events can cause a complete shutdown of plant-wide processes, which may take hours to return to normal operation.

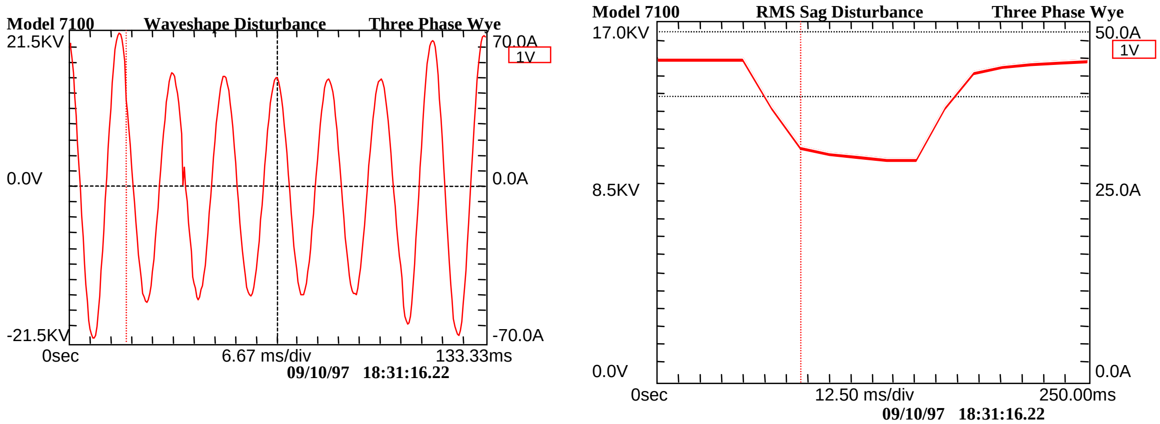

Figure 4-1
Waveform and RMS Voltage During Voltage Sag

Clearly, while the availability of power may have been 100% during a given period, the lack of quality due to sags during that period may result in significant unreliability and losses to some end-user processes. By installing power conditioning or battery systems near end use equipment it may be possible to mitigate sag events.

Long-Duration Variations

Long duration variations can be classified as RMS events that last longer than one minute. There are two standards that address these events, “The American National Standard for Electric Power Systems and Equipment Voltage Ratings” (ANSI C84.1), and IEEE Std. 1159-1995. The IEEE 1159 has three subcategories for long-duration variations: overvoltages, undervoltages, and sustained interruptions.

In contrast to sags and swells, long-duration voltage variations typically are not caused by system faults. The most common causes of long-duration variations are switching operations, large load variations, power system voltage regulation problems, and improper transformer tap settings. Depending on the design criteria for the equipment and its tolerances, a ten percent reduction in voltage may be sufficient to cause end use equipment to shut down. This is especially true if the equipment already is being supplied at a lower than rated voltage due to the wrong transformer taps or voltage drop due to a long cable run.

Voltage Unbalance

Voltage unbalance is defined as the percent deviation in the RMS value of the highest or lowest phase measured relative to the average RMS of the three-phase voltage. The calculation of voltage unbalance uses: (Maximum RMS voltage deviation from the average/average RMS voltage) * 100. In general, utility supply voltage is maintained at a relatively low level of phase unbalance since even a low level of unbalance can cause a significant power supply ripple and heating effects on the generation, transmission, and distribution system equipment. Utility supply voltages are typically maintained at less than two percent, and one percent is not uncommon.

Voltage unbalance more commonly emerges in individual customer loads due to phase load unbalances, especially where large, single-phase power loads are used, such as single-phase arc furnaces. Voltage unbalance of greater than two percent should be reduced, where possible, by balancing single-phase loads as phase current unbalance is usually the cause. A voltage unbalance can magnify the current unbalance in the stator windings of a motor by as much as 20 times, thereby causing substantial heating. Voltage unbalance is treated separately from unusually low or high voltage conditions that may occur during faults.

Waveform Distortion

Waveform distortion is defined as a steady-state deviation from an ideal sine wave at the power frequency. IEEE Std. 1159-1995 defines five subsets of waveform distortion: DC offset, Harmonics, Interharmonics, Notching, and Noise.

Voltage Fluctuations (Flicker)

Voltage fluctuations can cause lamps to flicker. Even a one percent voltage variation is capable of producing flicker that is perceptible to the human eye. The sensitivity of humans varies with the frequency of the fluctuations. Time varying loads such as arc furnaces and welders can cause slow (sub 60Hz) voltage variations. In turn, these fluctuations can cause incandescent lamps to "flicker" or change in their intensity with time. Although these fluctuations typically do not cause any disturbance on the power system, the flickering lamps become quite a nuisance.

Frequency Variations

Frequency variations are variations from the base 60-Hz power frequency. Frequency variations of the electric power system are extremely rare. Even slight variations could cause damage to electric power generators and turbine shafts. Frequency variations are more common on customer-owned generation running off grid. In the case of off grid generator operation, load turn on (or step loads) can cause frequency variations while the generator governor attempts to bring the machine back on the speed setting.

Power Quality Terminology

arrester discharge

The current that flows through an arrester due to a surge from IEEE[14]. The term *arrester discharge current* may be used to refer to a condition imposed on an arrester due to either lightning or switching surges occurring on the power system. It may also be in reference to a standard test waveshape which is used to characterize arrester protective levels [the amount of voltage occurring across the arrester during a discharge]. Typically, arresters are tested with

[14] IEEE C62.22-1991, IEEE Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems.

various waveshapes such as the 8/20 microsecond IEEE standard test wave as defined in IEEE Standard 4-1992 and C62. For medium and higher voltage arresters, these tests are usually performed at levels of 1.5, 5, 10, 20, and 40 kA.

Arrester discharge currents caused by lightning will vary greatly depending location of the arrester, the power system Basic Lightning Impulse Insulation Level (BIL) rating and interconnection configuration, the location of the lightning strike and many other factors. Arrester discharge currents due to lightning on typical medium voltage distribution circuits are typically less than 30 kA. Arrester discharge currents for low voltage circuits [600 volts or less] are usually much less than 10 kA but might occasionally be higher under unusual circumstances. Switching surge currents are ordinarily less than one thousand amperes on distribution circuits.

common mode voltage

A voltage that appears between current-carrying conductors and ground from IEC[15]. The noise voltage that appears equally and in phase from each current-carrying conductor to ground from IEEE[16].

Consider the case of a power circuit consisting of one or more phases, a neutral and a ground wire. It is possible for the ungrounded current-carrying conductors to assume undesired equal and in phase potentials such that no significant undesired voltage, would be measured between these conductors. However, a substantial undesired voltage could exist between the ungrounded current carrying conductors and ground.

Common mode voltages may be steady state and of very long duration, noise or may be short duration transients due to lightning and other surge phenomenon. Figure 4-2 displays an example of common mode voltage.

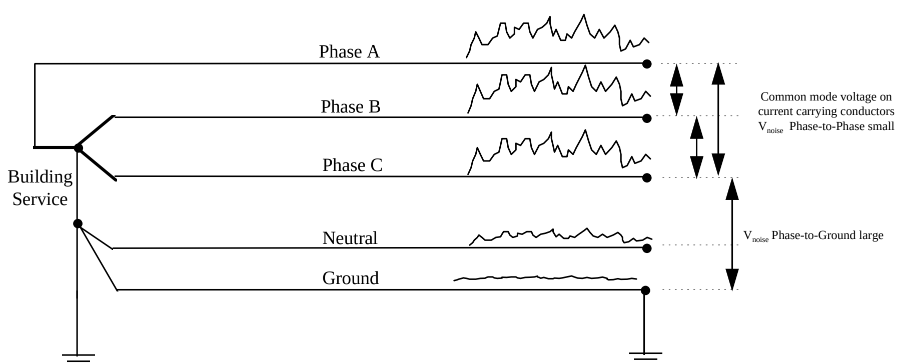

Figure 4-2
Typical Common Mode Voltage Conditions

[15] IEC 50(161)(1990) - International Electrotechnical Vocabulary, Chapter 161: Electromagnetic Compatibility.

[16] IEEE Standard 1100-1992, Recommended Practice for Powering and Grounding Sensitive Electronic Equipment. (Emerald Book).

critical load

Devices and equipment whose failure to operate satisfactorily jeopardizes the health or safety of personnel, and/or results in loss of function, financial loss, or damage to property deemed critical by the user. *Note:* This definition refers to function of the device, whereas the IEEE Std 100-1996 definition links the device to the quality of its power supply.

customer premises equipment (CPE)

Any equipment connected by customer premises wiring to the customer side of the demarcation point (network interface), used primarily by telecomm industry, see ANSI T1.318-1994.

dip (see sag)

distortion factor (harmonic factor)

The ratio of the root-mean-square of the harmonic content to the root-mean-square value of the fundamental quantity, expressed as a percent of the fundamental, from IEEE[17]. *Note:* Also referred to as *total harmonic distortion,* see IEEE Std 519-1992.

$$\text{DF} = \sqrt{\frac{\text{sum of squares of amplitudes of all harmonics}}{\text{square of amplitude of fundamental}}} \bullet 100\%$$

dropout

A loss of equipment operation (discrete data signals) due to noise, voltage sags, or interruption. (See IEEE Std 1159-1995.) The dropout voltage is the voltage at which a equipment fails to operate. Source. Equipment may cease operation at the dropout voltage for a variety of reasons. Typically, the dropout voltage refers to a low voltage condition. In the case of a voltage sag, often the dropout voltage will be accompanied by a duration that must transpire at the sag voltage for equipment to cease operation. In many cases, where the equipment is electronic in nature, a power supply consisting of diodes and capacitors performs an energy storage function for the equipment. The system components will only continue operation as long as the power supply is able to supply the internal voltage. Therefore, the dropout voltage is often a description of power supply performance for electronic equipment.

A common tool that is used to evaluate equipment performance within a certain environment is the Computer Business Equipment Manufacturers Association (CBEMA) curve. While the data shown in the curve was specifically developed for data processing equipment, it provides some insight into the operation of equipment supplied through a switched-mode power supply. Figure 4-3 shows the CBEMA curve.

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[17] IEEE STD 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.

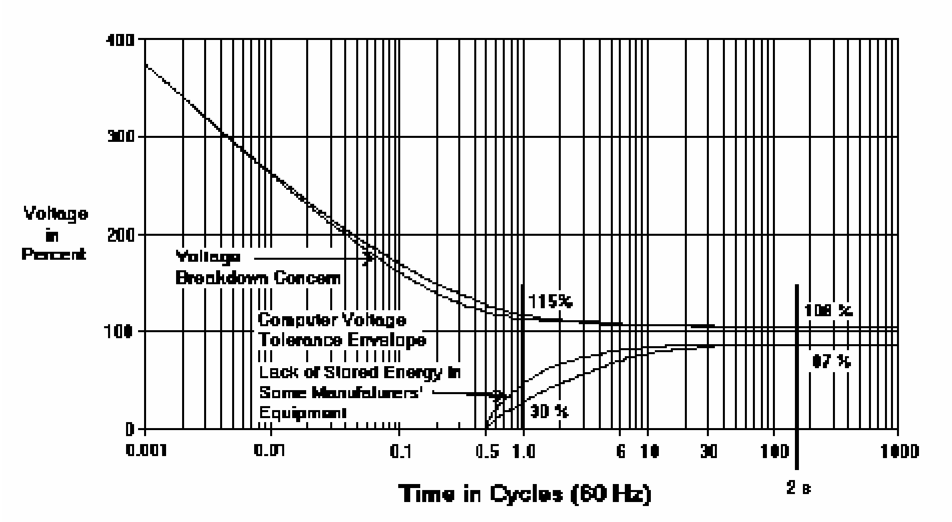


Figure 4-3
The CBEMA Curve, as Found in IEEE STD 446-1995

electromagnetic compatibility

The ability of a device, equipment or system to function satisfactorily in its electromagnetic environment without introducing intolerable electromagnetic disturbances to anything in that environment, from IEC 50161.

electromagnetic disturbance

Any electromagnetic phenomena which may degrade the performance of a device, equipment, or system, or adversely affect living or inert matter, from IEC 50161.

This is a very broad term and electromagnetic disturbances may involve both conducted and radiated signals of an electromagnetic origin. Examples include radio frequency signals from broadcast facilities, radio frequency interference from devices with oscillators or digital clocking circuits (computers, digital recording and playback equipment, communications equipment), electric and magnetic fields from power lines, noise which is conducted along conductors or radiated due to corona discharge and partial breakdown, lightning strikes (which have strong fields associated with them), and many other phenomena. As an example, a cloud-to-ground lightning flash involves a massive electrical breakdown of the air dieletric between cloud and ground. This breakdown and the subsequent flow of charge produces strong localized time changing electric and magnetic fields as well as somewhat weaker radiated electromagnetic waves with a broad band characteristics stretching from a few kilohertz up to hundreds of megahertz. These fields can cause problems for power systems and devices, especially those within 1 km of the flash location.

electromagnetic environment

The totality of electromagnetic phenomena existing at a given location, from IEC 50161.

This is the environment to which a system or device is exposed and considers all phenomena likely to be encountered at that location during its lifetime. For example, the electromagnetic environment for outdoor bus support mounted electronic equipment at a substation is radically different than that for an office computer deep within a commercial facility. The substation equipment will need to deal with strong power frequency fields due current flow through nearby bus-work. It may also be exposed to power line carrier signals, lightning fields and surges, and radio frequency noise due to corona discharge. The office computer deep within the office building would not likely be exposed to lightning fields or strong power frequency fields.

electromagnetic susceptibility

The inability of a device, equipment, or system to perform without degradation in the presence of an electromagnetic disturbance. Susceptibility is a lack of immunity, from IEC 50161.

This occurs when the fields due to an electromagnetic disturbance couple into the device or system in a manner which produces internal voltages and/or currents which cause it to operate improperly. For a device to properly operate in its intended working environment, it should be capable of handling the electromagnetic environment in which it is to be placed. A careful review of the types of fields and disturbances likely to occur at the equipment location should be performed. As an example, a sensitive monitoring instrument placed in a insulating enclosure (PVC plastic) and mounted near heavy current carrying conductors may not be adequately shielded from the magnetic fields of these conductors to operate properly. Methods to reduce susceptibility of devices usually involve shielding them from externally imposed fields with metal shields or enclosures. It also is important to shield all control, data and power supply entry cables or perhaps use filtering and/or surge suppression at these points to avoid entry of electromagnetic signals into the device, see immunity.

ferroresonance

A type of oscillatory transient with principal frequencies less than 300 Hz can be found on the distribution and/or network systems. These transients are generally associated with resonance resulting from the interaction of reactive impedance of capacitors with inductance from transformers. Such transients can involve series capacitors in a transformer electrical circuit. For example, these type of transients can occur when a network configuration results in magnification of low frequency components in transformer inrush current (2nd, 3rd harmonic) or when the capacitance of high voltage underground cables interact with the iron in local network phase shifting transformers.

flicker

Impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time, from IEC 50161, see **voltage fluctuation** for power quality causes of flicker.

Flicker on a power system refers to the varying luminance of light sources under conditions of varying supply voltage levels. Causes of voltage flicker include arc furnaces, motor starts and cycling on/off of large loads. The human eye has the greatest sensitivity to flicker in the range of 5-10 Hertz where even a small change of about 1/2% of nominal voltage can be perceived by the eye. Several curves are used in the industry, which plot the human eye sensitivity to flicker versus the frequency of occurrence. A curve known as the GE flicker curve is commonly used as a guide to determine the seriousness of a flicker condition. A typical flicker voltage condition is shown in Figure 4-4.

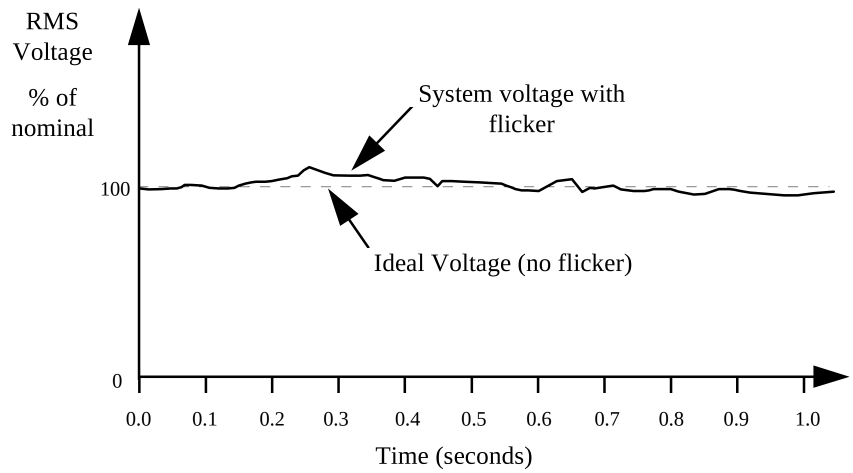


Figure 4-4
Voltage Flicker

frequency deviation

An increase or decrease in the power frequency. The duration of a frequency deviation can be from several cycles to several hours also called power frequency variation, from IEEE 1100.

Frequency deviations are defined as the deviation of the power system fundamental frequency from its specified nominal value (e.g. 50 Hz or 60 Hz). The power system frequency 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 depends on the load characteristics and the response of the generation system to load changes.

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.

Frequency variations that affect the operation of rotating machinery, or processes which derive their timing from the power frequency (clocks), are rare on modern interconnected power systems. Frequency variations of consequence are much more likely to occur when such equipment is powered by a generator isolated from the utility system. In such cases, governor response to abrupt load changes may not be adequate to regulate within the narrow bandwidth required by frequency sensitive equipment.

NOTE—Voltage notching can sometimes cause frequency or timing errors on power electronic machines that count zero crossings to derive frequency or time. The voltage notch may produce additional zero crossings which can cause frequency or timing errors. A small frequency disturbance is shown in Figure 4-5.

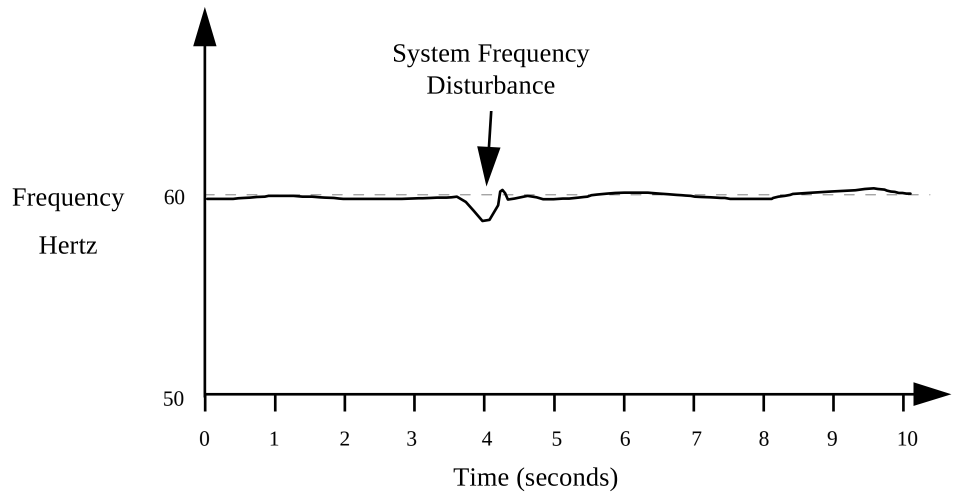


Figure 4-5
System Frequency Disturbance

fundamental (component)

The component of an order 1 (50 or 60 Hz) of the Fourier series of a periodic quantity, from IEC 50161.

The fundamental component refers to the expected power system signal when referring to power quality issues. For current and voltage in the United States, the fundamental component of the power delivered is 60 hertz. In reality, the delivered voltage and current drawn by a user is often not a pure sine wave. In these cases, mathematics provides the Fourier Transform to describe the components of a non-sinusoidal waveform. The result of a Fourier Transform mathematical operation on a continuous (not discrete) waveform is a Fourier series. A Fourier series is a representation of the discrete frequencies that compose the non-sinusoidal waveform. The zero component of the series is the direct current or DC component, and the first component is the fundamental component.

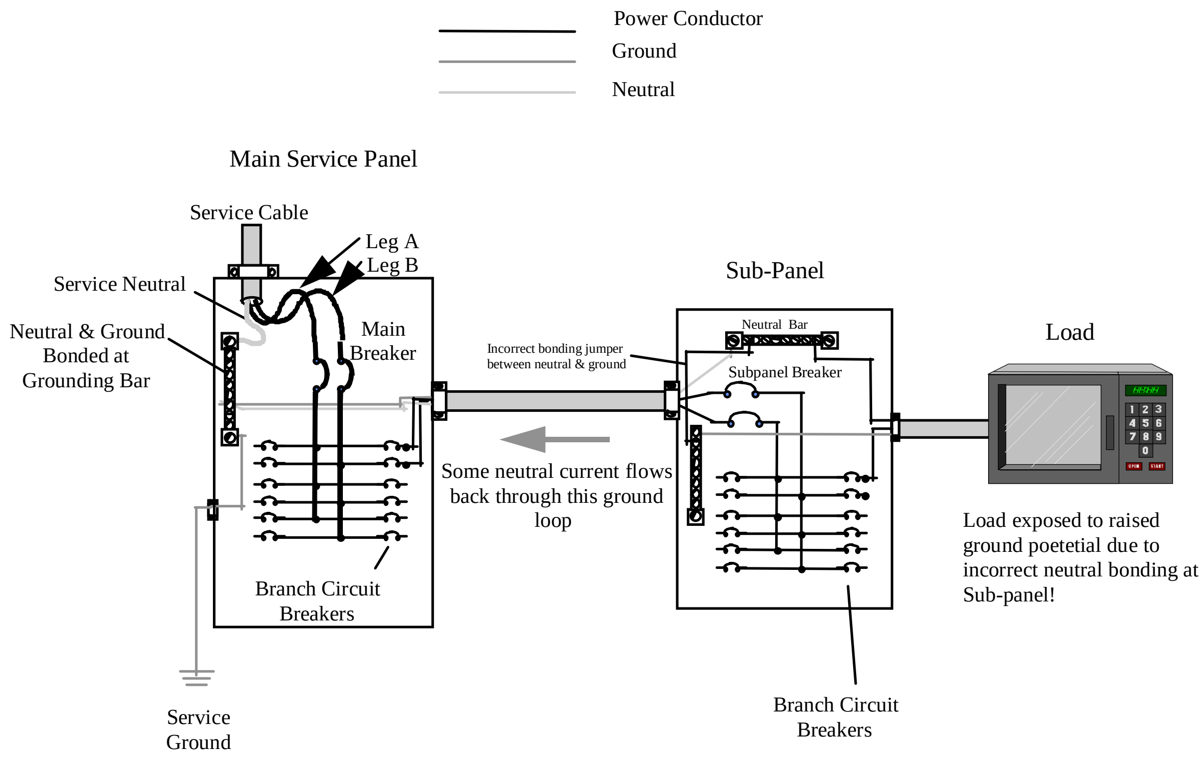


Figure 4-6
Ground Loop Example

harmonic content

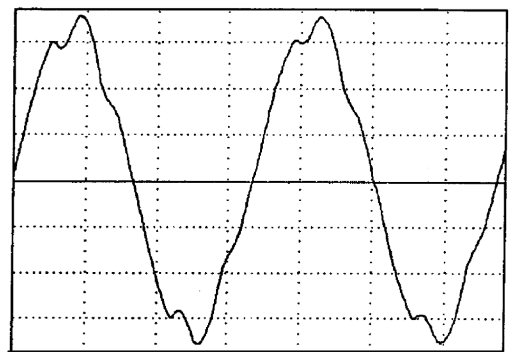
The quantity obtained by subtracting the *fundamental component* from an alternating quantity, from IEEE[18].

An alternating quantity is expressed in the Fourier series that describes the frequency components of the system. The series is typically a series of sinusoidal functions of differing frequencies and magnitudes. The harmonic content of the waveform is found by subtracting the fundamental component (order 1 component) from the Fourier series components. Typically, the harmonic content is also considered to have no direct current or DC (order 0) component.

[18] IEEE STD 100-1992, IEEE Standard Dictionary of Electrical and Electronic Terms (ANSI).

harmonic distortion

The mathematical representation of the distortion of the pure sine waveform, see distortion factor and Figure 4-7.



Source: The Dranetz Field Handbook

Figure 4-7
Distortion Example

immunity (to a disturbance)

The ability of a device, equipment or system to perform without degradation in the presence of an electromagnetic disturbance, from IEC 50161.

Immunity refers to the opposite case of electromagnetic susceptibility. The susceptibility refers to the inability of the device to operate in the presence of an electromagnetic disturbance, see electromagnetic susceptibility.

impulse

A *pulse* that, for a given application, approximates a unit pulse, from IEC 50161. When used in relation to the monitoring of power quality, it is preferred to use the term *impulsive transient* in place of *impulse*, from IEEE 1159, see transient and impulsive transient.

impulsive transient

A sudden non-power frequency change in the steady-state condition of voltage or current that is unidirectional in polarity (primarily either positive or negative), from IEEE 1159.

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 microsecond 2,000 V impulsive transient rises to its peak value of 2,000 V in 1.2 microseconds, and then decays to half its peak value in 50 microseconds. See the definition for basic lightning impulse insulation level (BIL) for more information regarding the waveform.

input power factor (of a system)

The ratio at the input of active power (measured in watts or kilowatts) to input apparent power (measured in volt-amperes or kilovolt-amperes) at rated or specified voltage and load, see power factor, displacement; power factor, total.

input voltage range (of a power system)

The range of input voltage over which the system can operate properly, see ANSI C84.1-1995.

inrush

The amount of current that a load or device draws when first energized.

instantaneous

A time range from 0.5-30 cycles of the power frequency when used to quantify the duration of a short duration variation as a modifier, from IEEE 1159. An instantaneous variation is of the category of a short duration variation. An instantaneous variation may take the form of an interruption, from[19], sag or swell, depending upon the magnitude of the variation. Table 4-2 shows the typical magnitudes of various instantaneous variations, see voltage variation, short duration.

Table 4-2
Typical Magnitudes for Instantaneous Short Duration Variations

Instantaneous Variation 0.5 cycles < $x \leq$ 30 cycles	Magnitudes
Interruption	< 0.1 pu
Sag	0.1 pu $\leq x <$ 0.9 pu
Swell	1.1 pu $< x \leq$ 1.8 pu

interharmonic (component)

A frequency component of a periodic quantity that is not an integer multiple of the frequency at which the supply system is designed to operate (e.g., 50 Hz or 60 Hz), form IEEE 1159. *See also:* waveform distortion. Interharmonics are typically caused by static power converters, induction motors, and arcing devices. The frequency of the interharmonic may appear as a single discrete frequency (induction motors) or could appear as a wide-spectrum distribution of many frequencies (arcing device).

[19] IEEE STD 1250-1995, IEEE Guide for Service to Equipment Sensitive to Momentary Voltage Disturbances.

interruption

The complete loss of voltage and/or current for a time period.

interruption, momentary (power quality monitoring)

(A) A type of short duration variation. (B) The complete loss of voltage (< 0.1 pu) on one or more phase conductors for a time period between 0.5 cycles and 3 s, see IEEE Std 1159-1995.

linear load

A load that draws a sinusoidal current wave when supplied by a sinusoidal voltage source.

loss of service

The loss of electrical power, a complete loss of voltage to one or more customers or meters. This does not include any of the power quality issues; sags, swells, impulses, or harmonics.

A loss of service implies that no voltage is present at the incoming connection between the energy user and the electric power utility. A sustained interruption is an event that is similar to the loss of service, however, loss of service implies that no voltage is present, where interruption implies that a small, but inconsequential (< 0.1 pu) of voltage may remain on the incoming lines.

momentary (power quality monitoring)

A time range at the power frequency from 30 cycles to 3 s when used to quantify the duration of a short duration variation as a modifier, from IEEE 1159. A momentary variation is of the category of a short duration variation. An instantaneous variation may take the form of an interruption, sag or swell, depending upon the magnitude of the variation. Also see voltage variation, short duration. Table 4-3 shows the relative magnitudes of the various momentary variations.

Table 4-3
Typical Magnitudes of Momentary Short Duration Variations

Momentary Variation **30 cycles < $x \leq$ 3 seconds**	**Magnitudes**
Interruption	< 0.1 pu
Sag	0.1 pu $\leq x <$ 0.9 pu
Swell	1.1 pu < $x \leq$ 1.8 pu

noise

Unwanted electrical signals which produce undesirable effects in the circuits of the control systems in which they occur, from IEEE 100. (For this document, control systems are intended to include sensitive electronic equipment in total or in part.), see waveform distortion.

Noise can constitute electrical signals that are propagated on an electrical circuit conductor, or those radiated electromagnetically through the environment. For example, noise may be introduced through coupling of one circuit to another where there is no physical connection between the two circuits. In addition, noise may be found on the equipment grounding conductor of a circuit caused by the operation of a device drawing a large current.

nominal voltage (Vn)

A nominal value assigned to a circuit or system for the purpose of conveniently designating its voltage class (as 208/120, 480/277, 600)[20]. ANSI/IEEE standard C84.1 specifies common nominal voltage ratings of AC power systems and also includes tolerance limits above and below the nominal voltage for which systems are intended to operate. For example ANSI C84.1 range A standards indicated the voltage should be maintained by the utility at the service entrance within +-5% of the nominal system voltage. For a system with a nominal voltage rating of 120 volts, this translates into a 114-126 volt range.

nonlinear load

Steady state electrical load which draws current discontinuously or whose impedance varies throughout the cycle of the input ac voltage waveform, from IEEE 1100.

Non-linear loads include devices such as saturable inductors and transformers, solid state switching devices like SCR's (silicon controlled rectifiers), IGBT's (Insulated gate bipolar transistors), and diodes. Non-linear loads are of particular concern since they produce harmonic currents and voltages that, if not limited to acceptable levels, may cause serious problems for the power system. Examples of loads which are classified as non-linear loads include light ballasts, switch mode power supplies (computers, consumer electronic devices), conventional dc power supplies and arc furnaces.

notch

A switching (or other) disturbance of the normal power voltage waveform, lasting less than a half cycle; which is initially of opposite polarity than the waveform, and is thus subtractive from the normal waveform in terms of the peak value of the disturbance voltage. This includes

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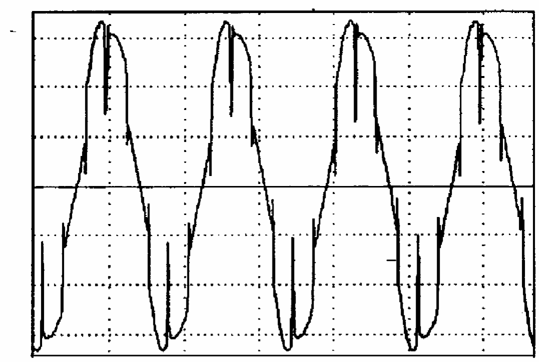
[20] IEC 1000-2-1 - Electromagnetic Compatibility (EMC) - Part 2 Environment, "Description of the Environment -- Electromagnetic Environment for Low Frequency Conducted Disturbances and Signaling in Public Power Supply Systems," Section 1, 1990.

complete loss of voltage for up to a half cycle, however, the typical duration is much shorter, as shown in Figure 4-8.



Source: The Dranetz Field Handbook.

Figure 4-8
Notches

oscillatory transient

A sudden, non-power frequency change in the steady state condition of voltage or current that includes both positive or negative polarity value, from IEEE 1159.

overvoltage

When used to describe a specific type of long duration variation, refers to an RMS increase in the ac voltage, at the power frequency, for a period of time greater than 1 min. Typical values are 1.1–1.2 pu. *See also:* swell; transient, from IEEE Std 1159-1995.

Overvoltages can be the result of load switching (e.g., switching off a large load), or variations in the reactive compensation on the system (e.g., switching on a capacitor bank). Poor system voltage regulation capabilities or controls result in overvoltages. Incorrect tap settings on transformers can also result in system overvoltages. Figure 4-9 shows a typical overvoltage waveform.

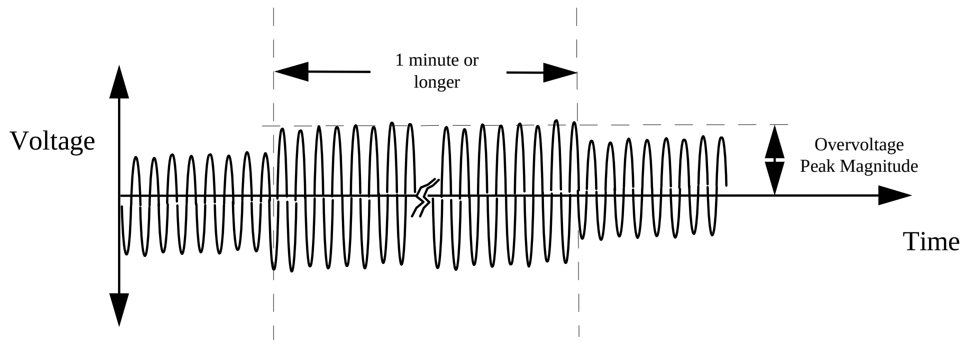


Figure 4-9
Typical Overvoltage Waveform

phase shift

The displacement in time of one waveform relative to another of the same frequency and harmonic content, from IEEE Std 1159-1995.

The classic definition for power factor involves a phase shift. In a power factor case, often, the current is lagging the voltage. The lagging term refers to the phase shift of the current with respect to the voltage. A phase shift is simply a time delay. In other words, the peak of the current sine wave arrives shortly after (a time delay) the peak of the voltage sine wave. Figure 4-10 shows a phase shift that may occur on a typical power system with current lagging the voltage.

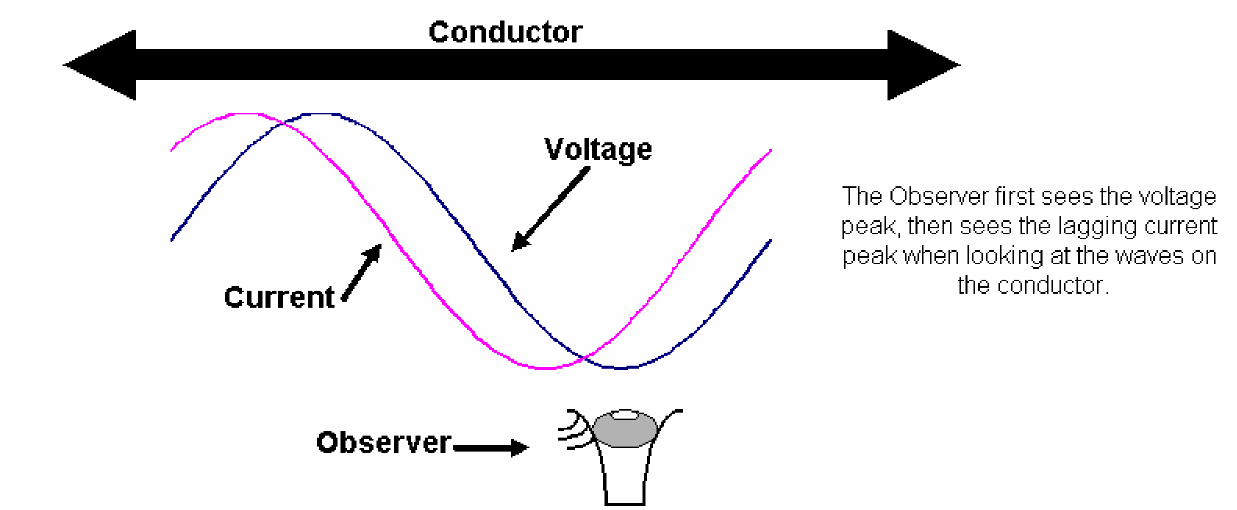


Figure 4-10
Typical Phase Shift on a Power System

power disturbance

Any deviation from the nominal value (or from some selected thresholds based on load tolerance) of the input ac power characteristics, from IEEE 1100.

When monitoring electric power, with many devices, thresholds are established to define what constitutes a power disturbance. Often, these thresholds are determined by the type of problem that is occurring. For example, if a certain piece of equipment is failing, device specific thresholds will be used (i.e. voltage limitations and noise limitations from the manufacturer) to establish the definition of a power disturbance.

power disturbance monitor

Instrumentation developed specifically to capture power disturbances for the analysis of voltage and current measurements.

power factor, displacement

The ratio of the active power of the fundamental wave, in watts, to the apparent power of the fundamental wave, in volt-amperes. Also the displacement component of power factor.

power factor, total

The ratio of the total power input, in watts, to the total volt- ampere input. *Note:* This definition includes the effect of harmonic components of current and voltage and the effect of phase displacement between current and voltage.

power quality

The concept of powering and grounding electronic equipment in a manner that is suitable to the operation of that equipment and compatible with the premise wiring system and other connected equipment, from IEEE 1100.

NOTE—Within the industry, alternate definitions or interpretations of power quality have been used, reflecting different points of view. Therefore, this definition might not be exclusive, pending development of a broader consensus.

A point of view of an equipment designer or manufacturer might be that power quality is a perfect sinusoidal wave, with no variations in the voltage, and no noise present on the grounding system. A point of view of an electrical utility engineer might be that power quality is simply voltage availability or outage minutes. Finally, a point of view of an end-user, is that power quality or “quality power” is simply the power that works for whatever equipment the end-user is applying. While each hypothetical point of view has a clear difference, it is clear that none is properly focused.

An environment where the equipment designer or manufacturer clearly states the equipment needs, and the electrical utility engineer indicates the system delivery characteristics, and the end-user then predicts and understands the equipment operational disturbances that will likely be encountered on a yearly basis is a better scenario. This allows a cost justification to be performed by the end-user to either improve equipment operation by installing additional components or improve the electrical supply system through installation of additional, or alteration of existing components.

pulse

An abrupt variation of short duration of an electrical quantity followed by a rapid return to the initial value, from IEEE 1159.

sag

An rms reduction in the ac voltage, at the power frequency, for durations from a half cycle to a few seconds. *Note:* The IEC terminology is *dip*, see notch and undervoltage.

To give a numerical value to sag, the recommended usage is "a sag to 20%," which means that the line voltage is reduced down to 20% of the normal value, not reduced by 20%. Using the preposition "of" (as in "a sag of 20%," or implied by "a 20% sag") is deprecated. A *sag* is a decrease in rms voltage or current at the power frequency for durations from 0.5 cycles to 1 minute. Typical values are between 0.1 pu and 0.9 pu.

Terminology used to describe the magnitude of a voltage sag is often confusing. A "20% sag" can refer to a sag which results in a voltage of 0.8 pu, or 0.2 pu. This Recommended Practice will indicate the *remaining voltage* throughout. Just as an unspecified voltage designation is accepted to mean line to line potential, so an unspecified sag magnitude will refer to the remaining voltage. For example, an 80% sag refers to a disturbance which resulted in a voltage of 0.8 pu. Where possible, also specify the nominal, or base, voltage level.

Voltage sags are usually associated with system faults but can also be caused by switching of heavy loads or starting of large motors. Figure 4-11 shows a typical voltage sag that can be associated with a single line-to-ground (SLG) fault. Also, a fault on a parallel feeder circuit will result in a voltage drop at the substation bus which affects all of the other feeders until the fault is cleared. Typical fault clearing times range from three to thirty cycles, depending on the fault current magnitude and the type of overcurrent detection and interruption.

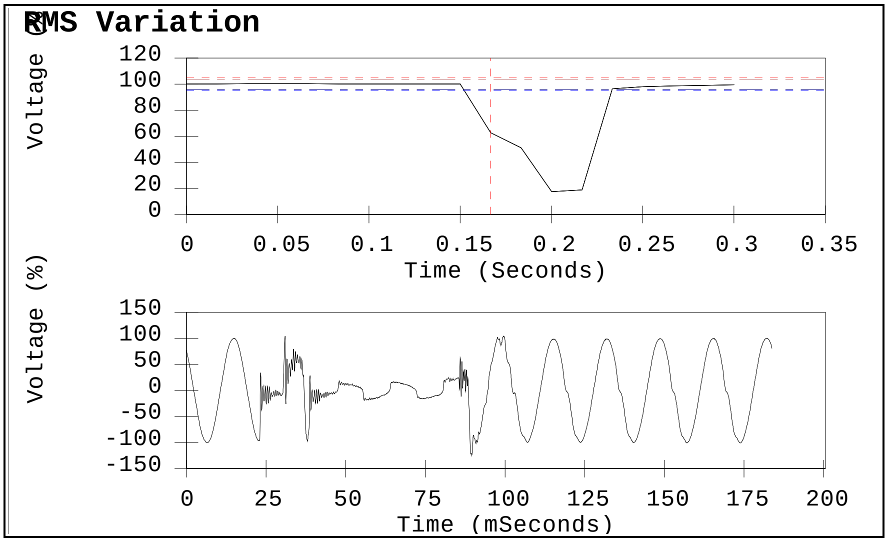


Figure 4-11
Instantaneous Voltage Sag Caused by a SLG Fault

Voltage sags can also be caused by large load changes or motor starting. An induction motor will draw six to ten times its full load current during starting. This lagging current causes a voltage drop across the impedance of the system. If the current magnitude is large relative to the system available fault current, the resulting voltage sag can be significant. Figure 4-12 illustrates the effect of a large motor starting.

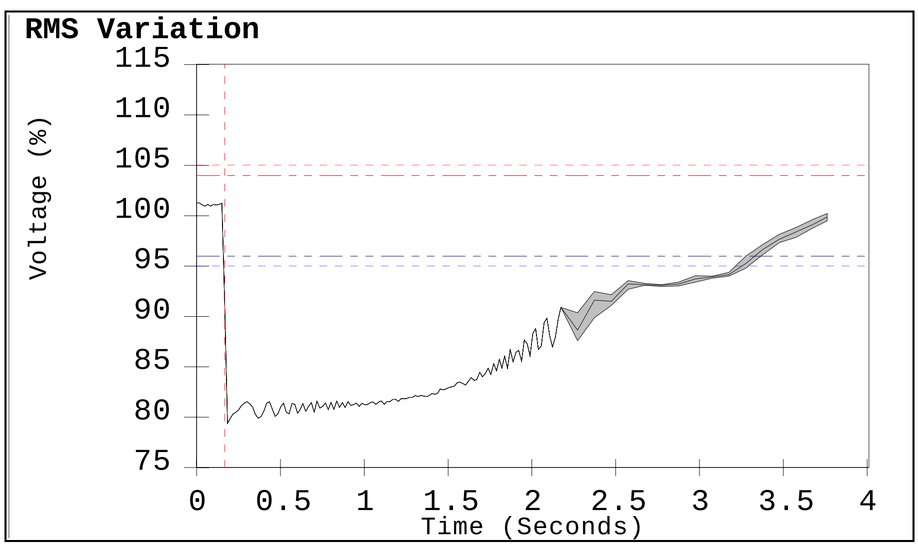


Figure 4-12
Temporary Voltage Sag Caused by Motor Starting

The term *sag* has been used in the power quality community for many years to describe a specific type of power quality disturbance, a short duration voltage decrease. Clearly, the notion is directly borrowed from the literal definition of the word sag. The IEC definition for this phenomenon is *dip*. The two terms are considered interchangeable, with *sag* being preferred in the United States power quality community.

Previously, the duration of sag events has not been clearly defined. Typical sag duration defined in some publications ranges from two milliseconds (about one-eighth of a cycle) to a couple of minutes. Undervoltages that last less than one-half cycle cannot be characterized effectively as a change in the rms value of the fundamental frequency value. Therefore, these events are considered *transients*. Undervoltages that last longer than one minute can typically be controlled by voltage regulation equipment and may be associated with a wide variety of causes other than system faults. Therefore, these are classified as long duration variations in the following section.

Sag duration is subdivided here into three categories -- instantaneous, momentary and temporary which coincide with the three categories of interruptions and swells. These durations are intended to correlate with typical protective device operation times as well as duration divisions recommended by international technical organizations.

shield

A conductive sheath (usually metallic) normally applied to instrumentation cables, over the insulation of a conductor or conductors, for the purpose of providing means to reduce coupling between the conductors so shielded and other conductors that may be susceptible to, or that may be generating unwanted electrostatic or electromagnetic fields (noise), from IEEE 1100.
Figure 4-13 depicts the configuration of a shield on a typical communication cable.

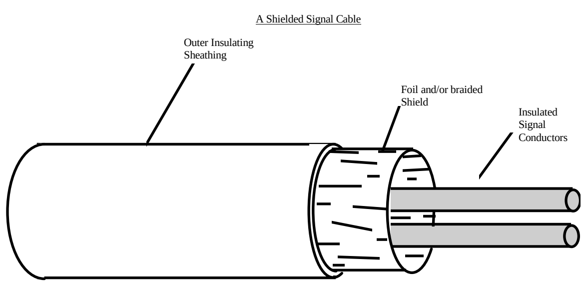


Figure 4-13
Diagram of the Shield within a Communication Cable

shielding

The use of a conducting and/or ferromagnetic barrier between a potentially disturbing noise source and sensitive circuitry. Shields are used to protect cables (data and power) and electronic circuits. They may be in the form of metal barriers, enclosures, or wrappings around source circuits and receiving circuits, from IEEE 1100.

surge

A transient wave of current, potential, or power in an electric circuit, from IEEE 100.

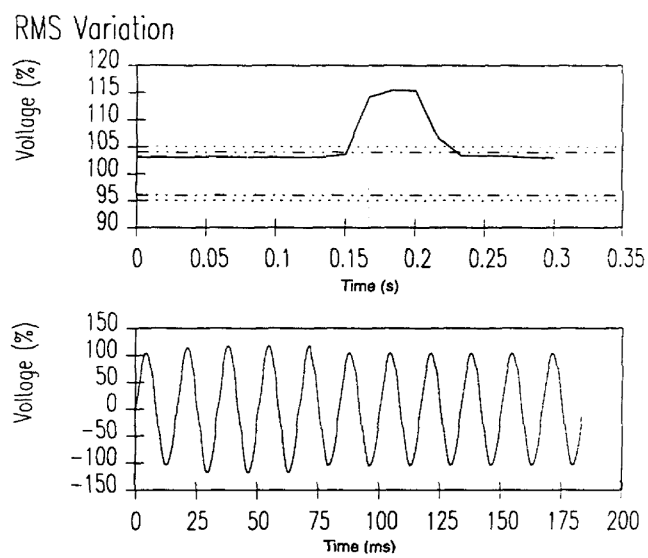
The use of the term surge is deprecated within the general power quality context. It is included in this text due to its extensive use within the IEEE C62 collection, *Surge Protection*. For the purposes of power quality definitions, surge is not to be used to describe transient electromagnetic phenomena, but the term transient shall be used, see transient.

surge protective device (SPD)

A device that is intended to limit transient overvoltages and divert surge currents. It contains at least one nonlinear component.

swell

An increase in rms voltage or current at the power frequency for durations from 0.5 cycle to 1.0 min. Typical values are 1.1–1.8 pu, from IEEE Std 1159-1995, see Figure 4-14.



Source: IEEE Std 1159-1995.

Figure 4-14
Swells Occurring Upon Recovery From a Remote System Fault

Swell magnitude is also described by its remaining voltage, in this case, always greater than 1.1.

As with sags, swells are usually associated with system fault conditions, but they are much less common than voltage sags. A swell can occur due to a single line-to-ground fault on the system resulting in a temporary voltage rise on the unfaulted phases. Swells can also be caused by switching off a large load or switching on a large capacitor bank. Figure 4-15 illustrates a voltage swell caused by a SLG fault.

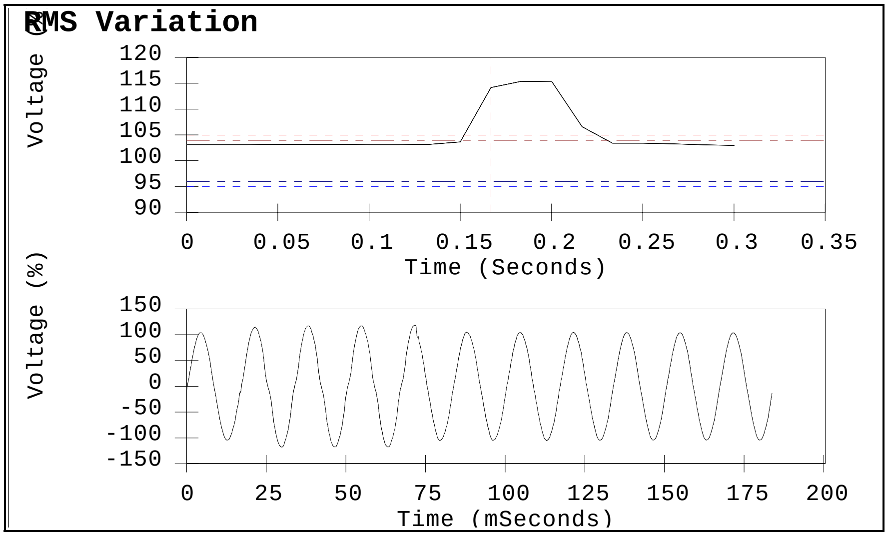


Figure 4-15
Instantaneous Voltage Swell Caused by a SLG Fault

Swells are characterized by their magnitude (rms value) and duration. The severity of a voltage swell during a fault condition is a function of the fault location, system impedance, and grounding. On an ungrounded system, the line-to-ground voltages on the ungrounded phases will be 1.73 per unit during a line-to-ground fault condition. Close to the substation on a grounded system, there will be no voltage rise on the unfaulted phases because the substation transformer is usually connected delta-wye, providing a low impedance zero-sequence path for the fault current.

In some previous publications, the term *momentary overvoltage* is used as a synonym for the term *swell*. A formal definition of swells in C62.41 is: "A momentary increase in the power-frequency voltage delivered by the mains, outside of the normal tolerances, with a duration of more than one cycle and less than a few seconds." This definition is not preferred by the power quality community.

telecommunications

Any transmission, emission, and reception of signs, signals, writings, images, and sounds, i.e., information of any nature by cable, radio, optical, or other electromagnetic systems, see TIA/EIA 607-1994.

tolerance

The allowable variation from a nominal value.

total harmonic distortion (THD)

This term has come into common usage to define either voltage or current “distortion factor,” from IEEE 519, see distortion factor.

transfer time (uninterruptible power supply)

The time that it takes an uninterruptible power supply to transfer the critical load from the output of the inverter to the alternate source, or back again.

transient

A subcycle disturbance in the ac waveform that is evidenced by a sharp, brief discontinuity of the waveform. May be of either polarity and may be additive to, or subtractive from, the nominal waveform. Pertaining to or designating a phenomenon or a quantity which varies between two consecutive steady states during a time interval that is short compared to the time scale of interest. A transient can be a unidirectional impulse of either polarity or a damped oscillatory wave with the first peak occurring in either polarity, from IEC 50161.

Broadly speaking, transients can be classified into two categories, *impulsive* and *oscillatory*. These terms reflect the waveshape of a current or voltage 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, then decays to half its peak value in 50 μs.

The most common cause of impulsive transients is lightning. Table 4-4 illustrates a typical current impulsive transient caused by lightning. Table 4-4 defines the spectral content and the duration of impulsive transients.

Table 4-4
Descriptions of Impulsive Transients

Impulsive Transients	Spectral Content	Duration
Nanosecond	5 ns rise	< 50 ns
Microsecond	1 μs rise	50 ns – 1 ms
Millisecond	0.1 ms rise	> 1 ms

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 within a building to another. Impulsive transients can excite power system resonance circuits and produce the following type of disturbance, oscillatory transients.

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 spectral content subclasses defined in Table 4-5 are high, medium, and low frequency. The frequency ranges for these classifications are chosen to coincide with common types of power system oscillatory transient phenomena.

Table 4-5
Descriptions of Oscillatory Transients

Oscillatory Transient	Spectral Content	Duration	Voltage Magnitude
Low Frequency	$x \leq 5$ kHz	0.3 – 50 ms	0 – 4 pu
Medium Frequency	5 kHz < $x \leq$ 500 kHz	20 μs	0 – 8 pu
High Frequency	500 kHz < $x \leq$ 5 MHz	5 μs	0 – 4 pu

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.

Oscillatory transients with a primary frequency component greater than 500 kHz and a typical duration measured in microseconds (or several cycles of the principal frequency) are considered *high frequency oscillatory transients*. These transients are almost always due to some type of switching event. High frequency oscillatory transients are often the result of a local system response to an impulsive transient.

Power electronic devices produce oscillatory voltage transients as a result of commutation and RLC snubber circuits. The transients can be in the high kilohertz range; last a few cycles of their fundamental frequency; and have repetition rates of several times per 60-Hz cycle (depending on the pulse number of the device) and magnitudes of 0.1 pu (less the 60-Hz component).

A transient with a primary frequency component between 5 and 500 kHz with duration measured in the tens of microseconds (or several cycles of the principal frequency) is termed a *medium frequency transient*.

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. Figure 4-16 below illustrates the resulting current transient due to back-to-back capacitor switching. Cable switching results in oscillatory voltage transients in the same frequency range. Medium frequency transients can also be the result of a system response to an impulsive transient.

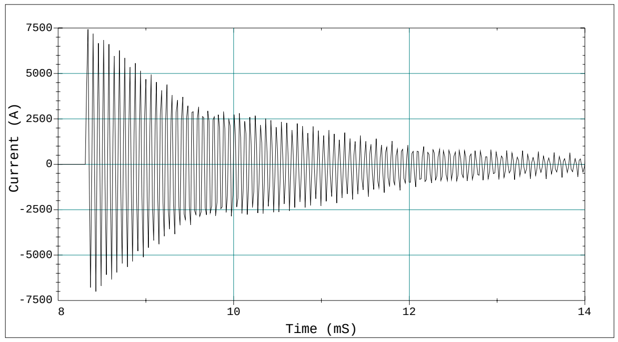


Figure 4-16
Oscillatory Transient Caused by Back-to-Back Capacitor Switching

A transient with a primary frequency component less than 5 kHz, and a duration from 0.3 ms to 50 ms, is considered a *low frequency transient*.

This category of phenomena is frequently encountered on subtransmission and distribution systems and is caused by many types of events, primarily capacitor bank energization. The resulting voltage waveshape 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 - 1.5 pu lasting between 0.5 and 3 cycles depending on the system damping (see Figure 4-17).

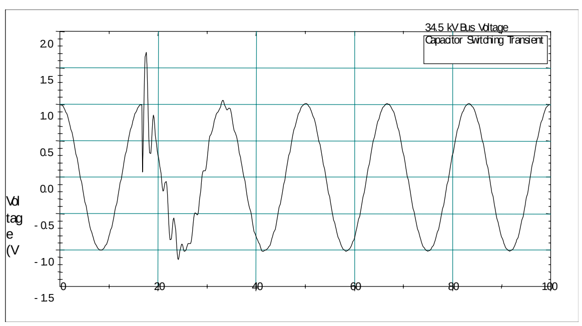


Figure 4-17
Low Frequency Oscillatory Transient Caused by Capacitor-Bank Energization

Oscillatory transients with principal frequencies less than 300 Hz can also be found on the distribution system. These are generally associated with ferroresonance and transformer energization. Transients involving series capacitors could also fall into this category. They occur when the system resonance results in magnification of low frequency components in the transformer inrush current (2nd, 3rd harmonic) or when unusual conditions result in ferroresonance as illustrated in Figure 4-18.

IEEE Standard C62.41 deals with defining standard impulsive and oscillatory transient test waves for the purpose of testing electrical equipment susceptibility and transient suppression technologies. This standard specifies voltage and current levels that certain pieces of power system equipment should be able to withstand.

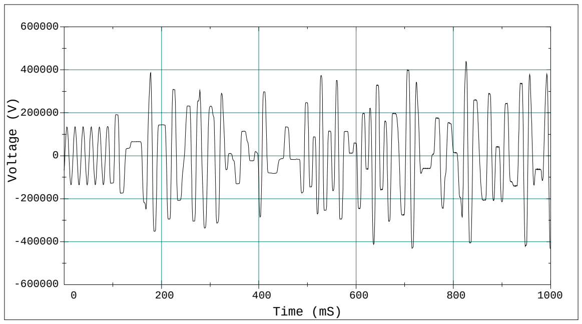


Figure 4-18
Low Frequency Oscillatory Transient Caused by Ferroresonance of an Unloaded Transformer

undervoltage

When used to describe a specific type of long duration variation, refers to an RMS decrease in the ac voltage, at the power frequency, for a period of time greater than 1 min. Typical values are 0.8–0.9 pu, from IEEE Std 1159.

Undervoltages are the result of the events which are the reverse of the events that cause overvoltages. A load switching on or a capacitor bank switching off can cause an undervoltage until voltage regulation equipment on the system can bring the voltage back to within tolerances. Overloaded circuits can result in undervoltages.

The term *brownout* is sometimes used to describe sustained periods of low power-frequency voltage initiated as a specific dispatch strategy to reduce power delivery. The type of disturbance described by brownout is basically the same as that described by the term undervoltage defined here. Because there is no formal definition for the term brownout, and because the term is not as clear as the term undervoltage when trying to characterize a disturbance, the term brownout should be avoided in future power quality activities in order to avoid confusion.

voltage change

A variation of the rms or peak value of a voltage between two consecutive levels sustained for definite but unspecified durations, from IEC 50161.

voltage dip see sag.

voltage distortion

Any deviation from the nominal sine wave form of the ac line voltage, from IEEE 1159.

voltage fluctuation

A series of voltage changes or a cyclical variation of the voltage envelope, from IEC 50161. Voltage fluctuations are systematic variations of the voltage envelope or a series of random voltage changes, the magnitude of which does not normally exceed the voltage ranges specified by ANSI C84.1 of 0.95 pu to 1.05 pu.

IEC 555-3 [this document has been revised as IEC 1000-3-3] defines various types of voltage fluctuations. The reader is referred to this document for a detailed breakdown of these types. The remainder of this discussion on voltage fluctuations will concentrate on the IEC 555-3 Type (d) voltage fluctuations. This type is characterized as a series of random or continuous voltage fluctuations.

Any load that has significant time variations, especially in the reactive component, can cause voltage fluctuations. Loads which exhibit continuous, rapid variations in load current magnitude can cause voltage variations erroneously referred to as *flicker*. The term *flicker* is derived from the impact of the voltage fluctuation on lighting intensity. Voltage fluctuation is an electromagnetic phenomenon and flicker is an undesirable result of that phenomenon. Even though there is a clear distinction between these terms -- cause and effect -- they are often confused to the point that the term “voltage flicker” is used in some documents. Such incorrect usage should be avoided.

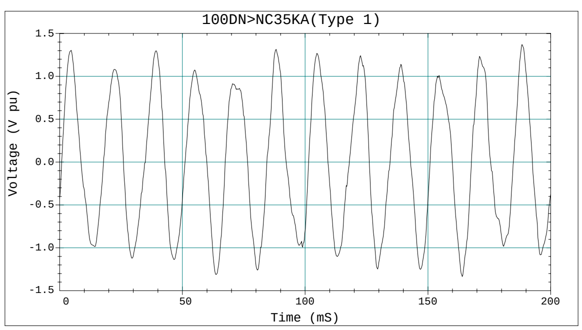


Figure 4-19
Example of Voltage Fluctuations Caused by Arc Furnace Operation

Arc furnaces are the most common cause of voltage fluctuations on the transmission and distribution system. The voltage signal is defined by its rms magnitude expressed as a percent of the fundamental. Lighting flicker is measured with respect to the sensitivity of the human eye. An example of a voltage waveform which produces flicker is shown in Figure 4-19.

Voltage fluctuations generally appear as a modulation of the fundamental frequency (similar to amplitude modulation of an am radio signal). Therefore, it is easiest to define a magnitude for the voltage fluctuation as the rms magnitude of the modulation signal. This can be obtained by demodulating the waveform to remove the fundamental frequency and then measuring the magnitude of the modulation components. Typically, magnitudes as low as 0.5% can result in perceptible light flicker if the frequencies are in the range of 6 – 8 Hz.

voltage imbalance (unbalance), polyphase systems

The maximum deviation among the three phases from the average three-phase voltage divided by the average three-phase voltage. The ratio of the negative or zero sequence component to the positive sequence component, usually expressed as a percentage, from IEEE 100.

Voltage imbalance (or unbalance) is defined as the ratio of the negative or zero sequence component to the positive sequence component. The negative or zero sequence voltages in a power system generally result from unbalanced loads causing negative or zero sequence currents to flow. Figure 4-20 shows an example of a one-week trend of imbalance measured at one point on a residential feeder.

Imbalance can be estimated as the maximum deviation from the average of the three phase voltages or currents, divided by the average of the three phase voltages or currents, expressed in percent. In equation form:

$$\text{Voltage Imbalance} = 100 \bullet \left(\frac{\text{maximum deviation from average voltage}}{\text{average voltage}} \right)$$

For example, with phase-to-phase voltage readings of 230, 232, and 225, the average is 229. The maximum deviation from the average among the three readings is 4. The percent imbalance is 100 * 4/229 = 1.7%.

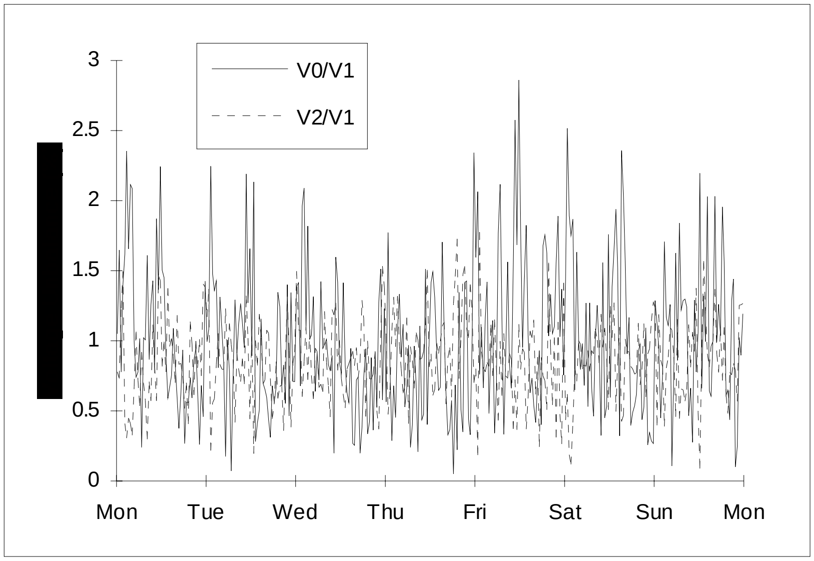


Figure 4-20
Imbalance Trend for a Residential Feeder

The primary source of voltage imbalance less than two percent is unbalanced single phase loads on a three-phase circuit. Voltage imbalance can also be the result of capacitor bank anomalies, such as a blown fuse on one phase of a three-phase bank. Severe voltage imbalance (greater than 5%) can result from single-phasing conditions. Figure 4-20 illustrates an imbalance trend for a residential feeder.

voltage regulation

The degree of control or stability of the rms voltage at the load. Often specified in relation to other parameters, such as input-voltage changes, load changes, or temperature changes, from IEEE 1100. Voltage regulation is calculated different ways depending on how the term is applied. As an example the voltage regulation at a customer service is often calculated in percent of nominal voltage and is:

$$\%Regulation = 100\,[V_{max}-V_{min}]/V_{nominal}$$

The above equation shows the percent change in voltage occurring relative to the nominal voltage. In some applications, it is chosen to compare the change in voltage relative to the average voltage which will yield a slightly different answer than the above formula. Regulation is also often calculated based on conditions of no load and maximum load which will yield an even greater variation.

voltage variation, long duration

A variation of the rms value of the voltage from nominal voltage for a time greater than 1 min. Usually further described using a modifier indicating the magnitude of a voltage variation (e.g., *Undervoltage*, *Overvoltage*, or *Voltage Interruption*), from IEEE 1159.

variation, short duration

A variation of the rms value of the voltage from nominal voltage for a time greater than 0.5 cycles of the power frequency but less than or equal to 1 minute. Usually further described using a modifier indicating the magnitude of a voltage variation (e.g. *Sag*, *Swell*, or *Interruption*) and possibly a modifier indicating the duration of the variation (e.g., *Instantaneous*, *Momentary* or *Temporary*), from IEEE 1159.

The short duration variation is the general category of events that last for a time period that is greater than 0.5 cycles, but less than or equal to 1 minute. It is not to be confused with steady state changes in the waveform such as harmonics, notching or noise, which can have a duration within the range of a short duration variation, but typically repeat for each cycle of the sinusoidal waveform.

Short duration variations are almost always caused by fault conditions, such as the energization of large loads that require starting current that is a multiple of the operating current (motors), or conditions such as loose connections in the current carrying circuit conductors. In addition, while most short duration variations are described as voltage variations in nature, current variations can also fall into the short duration variation as well. Figure 4-21 shows the time frame of the types of short duration variations.

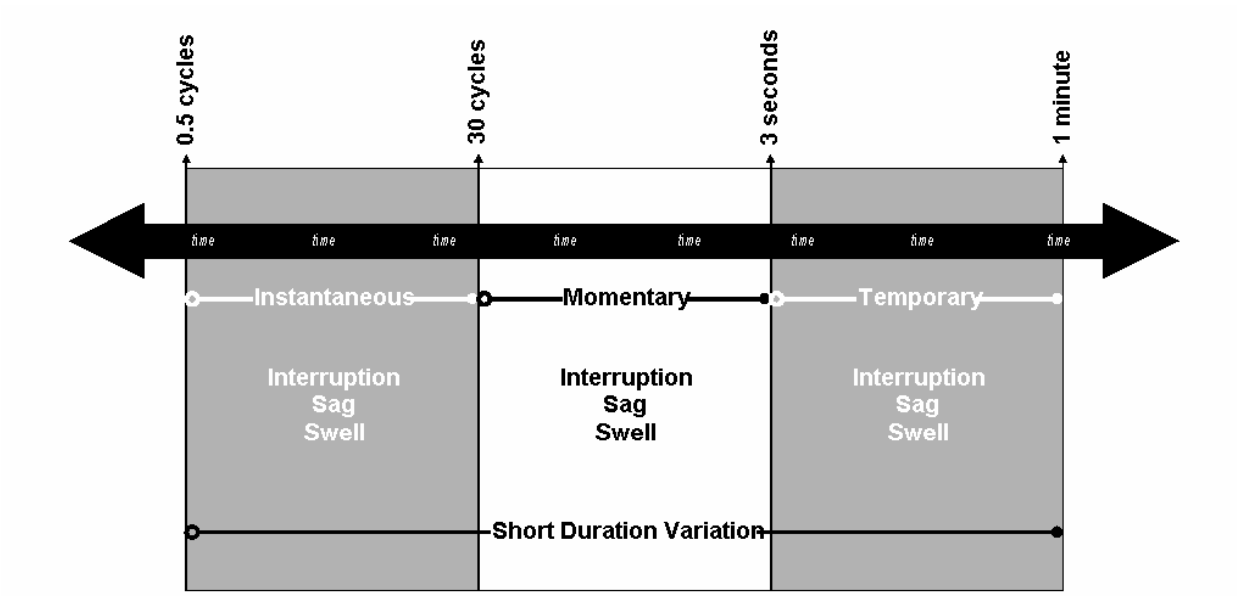


Figure 4-21
Time Scale of Short Duration Variations

waveform distortion

A steady state deviation from an ideal sine wave of power frequency principally characterized by the spectral content of the deviation), from IEEE 1159.

Power Quality Indices

Quality measurement parameters have been established for voltage sag, both magnitude and duration, acceptable harmonic distortion and unbalance levels. Both steady state conditions and momentary events need to be considered when measuring quality and establishing indices.

Over the past several years, voltage sags have been in the forefront of PQ activities in both the international and U.S. communities. Conferences, papers, and industry-standards activities regarding voltage sags are on the rise within the IEC and the IEEE and are an increasingly major concern for many consumers. Recognizing the importance of voltage variations to consumers, and perhaps in anticipation of regulators establishing voltage sag performance targets, some utilities have gone to the extent of voluntarily providing data to customers regarding expected voltage-dip performance. This section provides a summary of the indices, objectives of compatibility levels and limits, and existing levels that have been publish or are in working groups in IEEE and IEC.

In IEEE interruptions are covered along with other reliability indices in IEEE 1366. Sag indices are evolving in a new standards development effort designated as IEEE P1564. In 2003, CIGRE Working Group CIGRE C4.07/CIRED published a document describing recommended power quality indices along with summaries of benchmarking project results from around the world.. In November of 2001, the IEC published a technical report, IEC/TR 61000-2-8 (2002-11) Electromagnetic Compatibility (EMC) - Part 2-8: Environment - Voltage Dips And Short Interruptions On Public Electric Power Supply Systems with Statistical Measurement Results. This IEC document describes the electromagnetic disturbance phenomena of voltage dips and short interruptions in terms of sources, effects, remedial measures, methods of measurement, and measurement results.

Indices for Individual Voltage Dips

Single-events indices are used for troubleshooting and diagnostics. The calculation of single-event indices is an intermediate step in the calculation of site indices.

The recommended single-event indices are the retained voltage and duration of each voltage-dip event that shall be calculated in accordance with IEC 61000-4-30. It is recommended to measure the voltage in all three phases. IEC 61000-4-30 provides the recommended methodology for characterizing voltage dips (i.e. in terms of magnitude and duration).

For the measurement of dips, IEC 61000-4-30 states that “the basic measurement of a voltage dip and swell shall be $U_{rms(1/2)}$ on each measurement channel ($U_{rms(1/2)}$ is the value of the rms voltage measured over one cycle and refreshed each half cycle)’’.

From the rms voltage as a function of time two basic characteristics can be determined:

- Retained voltage or the dip depth - the retained voltage is the lowest Urms(1/2) value measured on any channel during the dip.
- Duration - the duration of a voltage dip is the time difference between the beginning and the end of the voltage dip.

Note that characterizing the duration of a voltage sag is very dependent on the choice of a threshold voltage. The threshold can be a percentage of either nominal or declared voltage, or a percentage of a sliding voltage reference, which takes into account the actual voltage level prior to the occurrence of a dip. The user shall declare the reference voltage in use.

It is also important to recognize that a voltage dip may not be adequately characterized by a magnitude and duration (this assumes a rectangular characteristic). The shape of the envelope may be assessed using several dip thresholds set within the range of voltage dip and voltage interruption threshold detection. The latter concept also called "Time Below Specified Voltage Threshold'' is presented in more details in reference [36]. Another method for treating non-rectangular dips is part of IEEE standard 493 [18] and discussed in detail in reference.

A number of other characteristics for voltage dips are mentioned in an annex to IEC 61000-4-30 including phase angle shift, point-on-wave, three-phase unbalance, missing voltage and distortion during the dip. The use of additional characteristics and indices may valuable and needed for individual investigations such as determining the source of the event and the impacts on equipment.

IEC 61000-2-8 also refers to the IEC 61000-4-30 for measurement, but introduces a number of additional recommendations for calculating voltage-dip indices. Recommended values are 90% and 91% for dip-start threshold and dip-end threshold, respectively, and 10% for the interruption threshold. Dips involving more than one phase should be designated as a single event if they overlap in time.

The IEEE P1564, Draft 5 [19], uses IEC 61000-4-30 as a base but also introduces two other single-event indices.

The voltage-dip energy is defined as:

$$E_{VS} = \int_0^T \left[1 - V(t)^2\right] dt$$

Eq. 4-1

with V(t) the rms voltage in per unit.

The integration is taken over the duration of the event, thus for all values of the rms voltage below the threshold. The voltage-sag severity S_e is defined from the retained voltage V in per-unit and the duration d by comparing these values with the so-called SEMI curve. The algorithm for calculating the voltage-sag severity proceeds as follows:

d ≤ 1 cycle: $S_e = 1 - V$ **Eq. 4-2**

1 cycle < d ≤ 200 ms: $S_e = 2(1 - V)$ **Eq. 4-3**

200 ms < d ≤ 500 ms: $S_e = 3.3(1 - V)$ **Eq. 4-4**

500 ms < d ≤ 10 s: $S_e = 5(1 - V)$ **Eq. 4-5**

d > 10 s: $S_e = 10(1 - V)$ **Eq. 4-6**

The calculation of site indices is an intermediate step in the calculation of system indices. Site indices are used namely for compatibility assessment between sensitive equipment and the power supply and can be used as an aid in the choice of a voltage-dip mitigation method. They can also be used to provide information to local customers on the voltage quality.

Site indices are calculated from single event indices. At locations where seasonal variations in the number of dips can be expected, the monitor period should be an integer multiple of one year. For locations with a strong seasonal variation in the event frequency, a three to five-year monitoring period is recommended to incorporate year-to-year variations in the seasonal effects.

Site indices can be presented in a number of different ways (see below for descriptions):

- As a voltage-dip table in accordance with the UNIPEDE-disdip [20] recommendation or the recommendations in IEC 61000-2-8
- As a contour chart according to IEEE 1346 [21]
- As the number of events more severe than a certain curve, e.g. ITIC or SEMI F47 curve [22], or below a certain retained voltage (e.g. SARFI indices)
- In any other way most suitable for the specific site and application

It is recommended that site indices be based on the remaining voltage in percent and the duration in milliseconds for individual events. It should be indicated if the pre-event or nominal voltage is used as a reference to calculate the relative remaining voltage. When using pre-event voltage, the sliding reference, as defined in IEC 61000-4-30, should be used. The sliding reference window may be used in HV and EHV systems with a relatively large variation in normal-operation voltage, when HV/MV transformers are equipped with on-line tap changers.

In many cases time aggregation is used to prevent double counting of events close together in time. Different methods of aggregation are in use, each with their advantages and disadvantages.

The monitor availability needs to be considered in calculating the event frequencies for the site indices from measurement data.

IEEE P1564 draft 5 [21] proposes a five-step procedure for characterizing voltage dip performance, starting with actual waveforms and progressing to the characterization of system voltage dip performance. The procedure is illustrated in Figure 4-22.

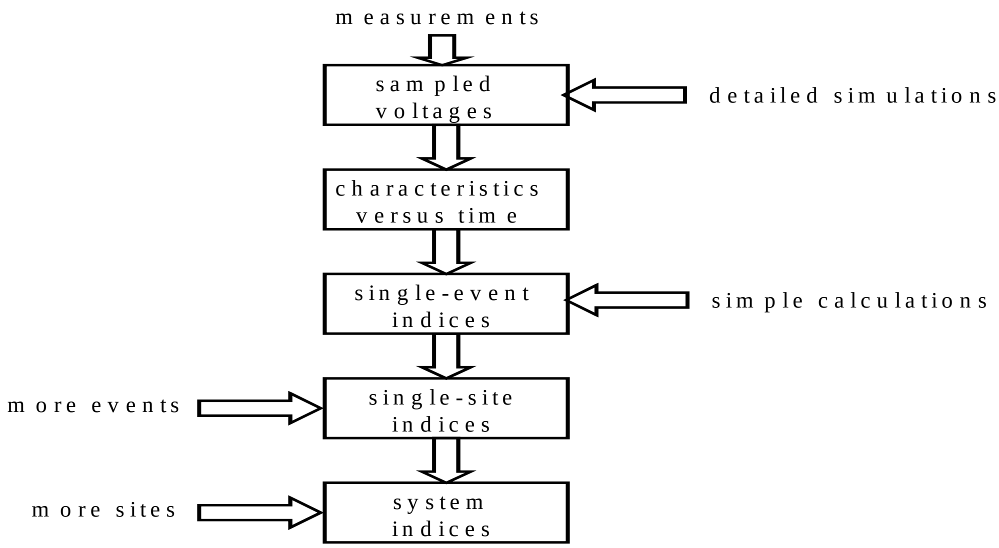


Figure 4-22
The Procedure for Obtaining Voltage Sag System Indices According to IEEE P1564 Draft 5

As indicated above, a number of different methods can be used for characterizing the voltage dip performance of a site or an entire system. Some of the prevalent methods are described here along with advantages and disadvantages of each method.

SARFI Indices

The most common voltage dip indices in use throughout the world are based on the concept of a System Average RMS variation Frequency Index or SARFI. The term "RMS variation" is used in US literature to indicate all events in which the rms voltage deviates significantly (typically seen as more than 10%) from its nominal value. This includes voltage dips, voltage swells and interruptions.

The $SARFI_X$ index (where X is a number between 0 and 100%) gives the number of events per year with a duration between 0.5 cycle and 1 minute and a retained voltage less than X%. Thus $SARFI_{70}$ gives the number of events with retained voltage less than 70%. Strictly speaking SARFI values are obtained as a weighted average over all monitor locations within a supply network or within part of the supply network. However the term is also used to refer to the event

[21] This draft can be subject to changes by the time it becomes a standard.

frequency at one location. By using the weighting factors, more weight can be given to location with more – or more important – load. The weighting factors are in most cases taken to be equal for all locations.

The SARFI-Curve index (where “Curve” is the name of a predefined curve) gives the number of events per year with a duration between 0.5 cycle and 1 minute, below the predefined curve. For example SARFI-SEMI gives the number of events more severe than the SEMI curve.

Advantages

The small number of indices makes it easy to compare different sites, different systems, and year-to-year variations.

The index depends primarily on the total number of events. When the indices are used to quantify system performance there will be strong incentive to reduce the number of faults. This also has a positive effect on the reliability (number of interruptions).

Disadvantages

The indices may not correlate with equipment sensitivity.

SARFI indices based on magnitude only do not provide any information about voltage dip durations. When these indices are used to quantify system performance, there is no incentive to reduce fault-clearing time.

The use of the (system) average makes it less appropriate as a system index. The method can be adjusted to cover 95 percentile values but that will make it more complicated.

Magnitude-Duration Tables

Site performance as well as system performance is often described in the form of a voltage-dip table. Different table formats are discussed in IEEE Std. 493 but only the so-called density table is in common use. The columns of the table represent ranges of voltage-dip duration; the rows represent ranges of retained voltage.

The choice of the magnitude and duration ranges for voltage-dip tables is a point of discussion. Different publications use different values.

The voltage-dip table recommended by the Unipede DISDIP group is given in Table 4-6.

Table 4-6
Voltage Dip Density Table Recommended By Unipede

	20-100ms	100-150 ms	0.5-1 sec	1-3 sec	3-20 sec	20-60 sec	60-180 sec	>180 sec
85-90%								
70-85%								
40-70%								
10-40%								
<10%								

The technical report IEC 61000-2-8 concludes that voltage dips should be classified by depth and duration in accordance with Table 4-7. Dips that involve more than one phase should be designated as a single event if they overlap in time.

Table 4-7
Voltage Dip Density Table as Recommended In IEC 61000-2-8

	1 cycl-0.1s	0.1-0.25s	0.25-0.5s	0.5-1s	1-3s	3-20s	20-60s	60-180s
80-90%								
70-80%								
60-70%								
50-60%								
40-50%								
30-40%								
20-30%								
10-20%								
<10%								

IEC 61000-4-11 prescribes a number of duration and retained voltage values for testing of end use equipment withstand levels for voltage dips. These values can be put in the form of a voltage dip density table, as shown in Table 4-8.

Table 4-8
Voltage Dip Density Table That Is Based on the Recommended Test Magnitudes and Durations in IEC 61000-4-11 According to IEEE P1564 Draft 5

Retained Voltage	Duration of the Voltage Sag				
	<1 cycle	1 cycle-200 ms	0.2-0.5 s	0.5-5 s	5s-5 min
70-80%					
40-70%					
10-40%					
≤10%					

Advantages

- The number of indices is limited but there is still a sufficient level of detail for comparison with system performance.
- Voltage-dip tables are easy to understand contributing to their wide use.
- The same format can be used for average, 50-percentile, 95-percentile and maximum value.
- The table covers everything from very short dips to long interruptions without any of these being able to overshadow the others.

Disadvantages

- The choice of duration values are not related to values actually occuring in practice for many of these tables. Many dips have a duration around 100 ms which can result in falling “in between” two cells. The 100-500 ms range (the most populous one in most surveys) is too wide to predict equipment performance.
- The duration ranges between 1 second and 3 minutes hardly ever contain any dips. Unless there is specific interest in short interruptions, these columns can be merged into one or two columns.
- For site and system comparison purposes the table is not practical. Cells can be merged for site indices and for average sites, but not for 95-percentile tables.

Voltage Sag Coordination Charts

A method for reporting site information from event magnitude and duration is described in IEEE Std.1346-1998 and in IEEE Std.493-1997. The method uses a “voltage sag coordination chart” to represent the expected voltage sag performance of the supply system. An example of such a chart is shown in Figure 4-23. The chart gives the number of events per year (sags and interruptions) as a function of the severity of the event. For the example shown here there is on average 1 event per year where the voltage drops below 50% for 100 ms or longer. There is also on average 1 event per year more severe than 80%, 80 ms and on average 0.1 event per year below 70% for longer than 500 ms.

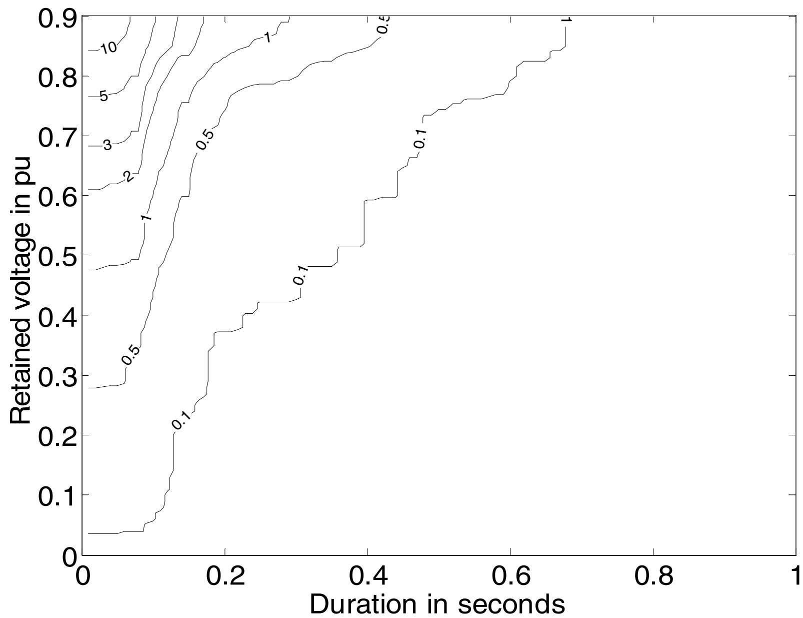


Figure 4-23
Example of A Voltage Sag Coordination Chart Representing Voltage Sag Performance of HV Sites (Based on Procedure Defined in IEEE 1346)

Advantages

- The chart can be directly compared with equipment performance. This makes the method very suitable for data exchange between network operator and industrial customer.
- The data can be reprocessed into most other indexing methods without significant loss of information.

Disadvantages

- The method is somewhat complicated and difficult to explain.
- A simple comparison between sites is not possible because of the many variables involved.
- When used as a system index the average is used which makes it less suitable as an index. The method may be adjusted to cover 95 percentiles but the result would be even more complicated.

NRS 048 Method

The NRS 048 standard defines specific areas on a magnitude/duration plane that attempt to provide generalized guidelines on areas where dips are likely to occur, and areas that customers are likely to be affected. The aim of these generalized areas is to reduce the number of indices that need to be reported and managed, based on the most "appropriate" grouping of dip events.

Table 4-9
NRS-048-2: 2003 Dip Reporting Method

<table>
<tr><th rowspan="2">Retained Voltage U</th><th colspan="3">Duration t</th></tr>
<tr><th>20 ≤ t < 150 (ms)</th><th>150 ≤ t < 600 (ms)</th><th>0.6 ≤ t < 3 (s)</th></tr>
<tr><td>90> U ≥ 85</td><td colspan="3"></td></tr>
<tr><td>85> U ≥ 80</td><td colspan="2">Y</td><td rowspan="2">Z1</td></tr>
<tr><td>80> U ≥ 70</td><td></td><td rowspan="3">S</td></tr>
<tr><td>70> U ≥ 60</td><td>X1</td><td rowspan="3">Z2</td></tr>
<tr><td>60> U ≥ 40</td><td>X2</td></tr>
<tr><td>40> U ≥ 0</td><td colspan="2">T</td></tr>
</table>

The categorization method adopted by NRS-048-2: 2003 in South Africa is shown above in Table 4-9. The Y-type (grey) area reflects dips that are expected to occur frequently on typical HV and MV systems, and against which customers should protect their plant. The X-type areas (X1 and X2) reflect "normal" HV protection clearance times and hence a significant number of events are expected to occur in this area. Customers with sensitive equipment should attempt to protect against at least X1 type dips that are more frequent. The T-type area reflects close-up faults, which are not expected to happen frequently - and which a utility should specifically address if excessive. S-type dips are not as common as X and Y type events, but may occur where impedance protection schemes are used, or where voltage recovery is delayed. Z-type dips are very uncommon on HV systems (particularly Z2-type events), as this generally reflects problematic protection operation. These may be more common on MV systems.

Advantages

- A relatively small number of indices. The values in the X, S, T and Z cells enable utility dip-performance reporting.
- It has all the advantages of a voltage-dip table (see UNIPEDE table)
- There is a direct relation with system properties (leading to typical clustering of events) and with equipment immunity properties.

Disadvantages

- The table is not commonly used outside of Southern-Africa (and is actually somewhat specific to protection practices in South Africa).
- The table stops at 3 seconds making it less suitable for including short interruptions.

5
RELIABILITY

Power system reliability is the over arching objective of SQRA. It encompasses the time an electric system is available, the frequency of failures, the various type of failures, and contingencies that define operating margins or when single component failures may result in system failures. The definition of a failure and the probability that a failure will occur are both key aspects of reliability.

One commonly accepted view on what system reliability should include is everything that may serve to reduce the probability that a failure will occur. Along the same line, high reliability should increase a power system's availability and reduce the number of failure events. However, these two measures are not necessarily improved in equal portions. For example specific actions may significantly reduce the number of failures, while long repair times for remaining failure events still result in poor system availability.

In the context of SQRA we consider power system reliability as the probability the system will operate properly during a specific period of time, and including the quality requirements of the end use equipment. This reliability will depend on power system design, component selection, definition of failures, and the operating environment. One challenge for today's electric power system is that new power quality related failure modes of the end-user equipment and processes are impacting the customer's perception of power system reliability. One of the more common examples of this impact is when sensitive industrial and data processes fail due to very brief voltage interruptions or voltage quality problems. Similarly power system security issues can increase the probability of failures. Thus the level of power quality or security needs to be considered in measuring overall electric power system reliability.

Attributes of Power System Reliability

Although the word reliability is used in several different contexts in daily verbiage, it is formally defined in the technical literature as: "the probability that a product or service will operate properly for a specified period of time (design life) under the design operating conditions (such as temperature or voltage) without failure[22]." In context of industrial or military systems reliability is typically defined as the length of time between failures under some specified

[22] **E. A. Elsayed**, (1996), *Reliability Engineering* (with Solution and Software), Addison-Wesley, 780 pages. This book received the 1997 IIE Joint Publisher Book-of-Year Award. **E. A. Elsayed** and T. O. Boucher, (1994), *Analysis and Control of Production Systems* (with Solution and Manual), Prentice-Hall, Inc., 450 pages, Second Edition.

conditions. Historically, the electrical power industry has used outage time relative to total time and total number of customers.

Unlike the utility industry, reliability for industrial processes and military systems focuses on frequency of system failure. Frequency of system failure is the “mean number of system failure or outage per unit time.” The unit of time depends on the system. Further designation of reliability based on time is Mean-Time-Between-Failure (MTBF). This index is the average time elapsed between two consecutive failures. It is given by MTBF = 1/ (Frequency of failure rate). Also the expected failure duration is defined as the “expected or long-term average duration of a single failure event.” Related to this index is the Mean Time to Repair (MTTR) that is frequently used in the calculation of system reliability.

Looking to the future we expect utilities to broaden their view and there measures of reliability and reliability prediction. A number of methods are being looked at and some are gradually gaining acceptance in the electric industry. Reliability assessment and evaluation methods based on probability theory that allow the reliability of a proposed system to be predicted quantitatively are finding wide application today. Such methods permit consistent, defensible, and unbiased assessments of system reliability that are not otherwise possible. Also, considering the industrial reliability measure of number of failures and time between failures is also gaining some acceptance.

Planning for reliable power requires a total system viewpoint including consideration of the service reliability, the local electrical distribution design, and the requirements of end-use loads. A prediction of reliability involves the individual reliability of all components required to deliver power. Therefore reliability is reduced by distance and number of components between the main power source and the equipment to be served. Conversely, reliability is more likely increased by providing alternate delivery paths and additional sources of generation or by simply placing the generator closer to the point of use. SQRA measure should help to identify where local generation and modifying service entrance play a significant role in adding reliability to an electric power system.

Conventional Measures of Reliability

The term reliability in the context of electric power systems is generally used to indicate the ability of a system to continue to perform its intended function. In its simplest form we consider that power is either available or not. And the measurement indexes that have proven to be most useful and meaningful in power distribution system design from[23] [24], are:

- Load interruption frequency (number/unit time)
- Expected duration of load interruption events (time)

[23] Billinton, R., and Allan, R. N., “Reliability Evaluation of Power Systems,” Plenum Publishing Corp., 1983.

[24] Ayoub, A. K., and Patton, A. D., “A frequency and duration method for generating system reliability evaluation,” *IEEE Transactions on Power Apparatus and Systems,* Nov. Dec. 1976, pp. 1929–1933.

These indexes can be computed and then used to compute other indexes that are useful:

- Total expected (average) interruption time per year (or other time period)
- System availability or unavailability as measured at the load supply point in question
- Expected demanded, but unsupplied, energy per year

These measures become more complicated when different degrees of performance and failure are considered. The disruptive effect of power interruptions is often non-linearly related to number of phases effected and duration of the interruption. Thus, it is often desirable to compute not only an overall interruption frequency but also frequencies of interruptions categorized by the appropriate durations. This is particularly important in cases where no interruption occurs and the issue is voltage quality, the varying degrees and the different effects of unbalance, sags or swells, as discussed earlier.

Frequency and Duration of Interruptions

The concept of a momentary interruption is used to define events that are generally cleared by automatic interventions. The concept of sustained interruptions is used to define events that are generally related to operator interventions. The duration shall be declared as part of the reporting. For the purpose of most reliability indices, the differentiation of momentary and sustained interruptions is recommended as a fixed duration of 1 minute up to 3 minutes, i.e.:

- A momentary interruption is defined as an interruption of duration 1 minute up to 3 minutes.
- A sustained interruption is defined as an interruption of duration greater than 1 minute up to 3 minutes

The frequency of short-duration interruptions has been quantified by various PQ surveys, including the EPRI Distribution Power Quality Project. These surveys, taken at different points in the distribution and end use systems, provide a good comparison on how events propagate through the power system. Such a comparison is made in Table 2-2 for two large North American surveys, the EPRI Distribution Power Quality (DPQ) survey and the National Power Lab (NPL) survey. The EPRI survey monitored both distribution substations and distribution feeders. The NPL survey monitored power receptacles inside an end user facility. This data shows that the overall trend is for the number of short interruptions to increase when moving from the power source to the load.

Table 5-1
Interruption Frequency (per Year) From EPRI DPQ and NPL Surveys

Number of Events by Duration Range									
Point of Survey	1-6 cycles	6-10 cycles	10-20 cycles	20-30 cycles	0.5-1 sec	1-2 sec	2-10 sec	> 10 sec	Total all Durations
Substations (EPRI)	0.2	0.1	0.4	0.8	0.5	0.9	1.1	1.3	5.3
Dist. Feeders (EPRI)	1.6	0.1	0.2	0.6	0.5	1.1	2.3	1.7	8.8
Premises LV (NPL)	0.2	0.3	0.7	0.8	1.2	1.5	3.3	4.2	12.2

Similar conclusions can be drawn from the Canadian Electric Association (CEA) service entrance survey and from the Norwegian research lab (EFI) distribution primary and secondary voltage survey. These results are shown in

Table 5-2 and Table 5-3.

Table 5-2
Interruption Frequency (Per Year) from CEA Survey in Canada

Number of Events by Duration Range									
Point of Survey (CEA)	1-6 cycles	6-10 cycles	10-20 cycles	20-30 cycles	0.5-1 sec	1-2 sec	2-10 sec	> 10 sec	Total all Durations
Service Primary	1.9	0.0	0.1	0.0	0.4	0.0	0.0	0.7	3.1
Service Secondary	3.7	0.0	0.0	0.0	0.2	0.5	0.5	2.1	7.0

Table 5-3
Interruption Frequency (Per Year) for Distribution and Low-Voltage Systems in Norway

Number of Events by Duration Range							
Point of Survey (EFI)	0.01-0.1 sec	0.1-0.5 sec	0.5-1.0 sec	1-3 sec	3-20 sec	> 20 sec	Total all Durations
Service Primary	1.5	0.0	0.0	0.0	0.5	5.2	7.2
Service Secondary	1.1	0.7	0.0	0.7	0.9	5.9	9.3

Major Events vs. Underlying Events

Major events include extreme weather conditions (e.g. ice storms) and natural disasters (e.g. earthquakes). By their nature, major events may have an overbearing effect on the reported indices. For this reason, some utilities report these separately from underlying events (the majority of smaller events on the system over the reporting period).

Major events (Cigre definition): In questionnaires sent out by Cigre on major incidents in the 1970's and again in the 1980's, major incidents were defined as those for which the degree of severity exceeded 1 system minute on systems having a maximum demand in excess of 1000 MW (this was reduced to 500MW in the second survey) [30].

Major events (USA - DOE): In the USA, mandatory reporting of major events is required by transmission operators to the Department of Energy. The following criteria define such events.

- Any load shedding actions resulting in the reduction of over 100 megawatts (MW) of firm customer load for reasons of maintaining the continuity of the bulk electric power supply system.
- Equipment failures and system operational actions associated with the loss of firm system loads for a period in excess of 15 minutes, as described below:
- Reports from entities with a previous year recorded peak load of over 3 000 MW are required for all such losses of firm loads which total over 300 MW;
- Reports from all other entities are required for all such losses of firm loads which total over 200 MW or 50% of the system load being supplied immediately prior to the incident, whichever is less.
- Other events or occurrences which result in a continuous interruption for three hours or longer to over 50,000 customers, or more than 50% of the total customers being served immediately prior to the interruption, whichever is less.

IEEE-1366 (distribution systems): A major incident is defined by many distribution companies and regulators as one in which more than 10% of customers are affected in any 24 hr period. As the term is (later in the document) also used as an interruption cause code, it may in some cases be used by a distribution utility to define a loss of transmission supply. IEEE 1366 allows the exclusion of specific incidents such as: major events, scheduled interruptions, and interruptions out of the control of the utility. The primary aim of this method of reporting is to relate a set of data that has direct bearing on the design of the system. The latest version of IEEE 1366 (2003) provides a new definition of major events based on events that are more than 2.5 standard deviations away from the mean with the assumption of a log-normal distribution of daily interruption statistics.

IEEE-859 (transmission systems): Provides standard terms for reporting and analyzing outage occurrences and outage states of electrical transmission facilities. This standard was reaffirmed in 2002. Although focusing mainly on the reporting of transmission *equipment* outages (as opposed to system outages), it also defines a major storm disaster as anytime equipment design levels are exceeded, and all of the following conditions are met:

- Extensive mechanical damage is evident;
- More than a specified percentage of customers have been affected;
- Service restoration takes longer than a specified time.

Significant events (New Zealand): TransPower defines major events as those greater than 1 system minute. These are reported in the total annual figures, but removed when describing "underlying performance". A detailed list of all such major interruptions since 1987 is published annually, together with a description of the cause of each of these [32].

A general requirement in most countries is that major events are defined in detail.

Various utilities and regulatory bodies have defined specific technical and other criteria that may be used to identify events, which can be removed from the reported indices. Examples of these, primarily for distribution systems, are:

- Wind of over 80 mph [33];
- More than 1/2 inch ice loading [33];
- Earthquakes, fires, or storms of sufficient intensity to give rise to a state of emergency being declared by the government [34];
- Specific agreement between the utility and the regulatory body;
- The National Weather Service having issued a watch or warning for the area [35];
- Extensive mechanical damage [35];
- More than 10% of customers out during or immediately after the storm effects [35];
- At least 1% of the customers out after 24 hrs after the storm damage period [35].
- Planned and Unplanned Events

Some utilities differentiate between planned and unplanned (forced) interruptions when reporting, while other utilities include both planned and unplanned events in a single index. This often depends on the nature of the transmission system. Utilities with more dominantly radial systems tend to differentiate the indices, whereas those with more meshed systems tend to include both in each of their indices.

Planned interruptions are generally defined as those where customers have been given advance notice with a corresponding minimum notice period (e.g. 2 weeks before the event).

Unplanned interruptions are generally defined as those which could not be avoided and where advance notice could not be provided within the required notice period. In some cases, planned interruptions, which exceed the planned duration, are considered as unplanned events for the excess period.

Availability as a Measure of Reliability

Availability is one measure of power system reliability that has gained popularity lately as the economy moves from the industrial age to the high-tech digital age. This "index of nines" has been used to measure the uptime of a process and has been a commonly used metric to define the availability requirement for mission-critical facilities. And it has been used for quite some time in MIL Standards and other component or system reliability standards to describe the probability that a system or component will be available.

In this case availability (or up time) of a component or system is based on its mean time between failure (MTBF) and mean time to repair (MTTR). For example, if the MTBF of a 480-V metal-clad switchgear is 0.0012 failures per year (λ) and if the MTTR is 0.0108 hours per year (r), then the total downtime you would expect from the component is a product of λ and r, or 0.0012 X 0.0108 = 0.00001296 hours, an "unavailability" of 0.046656 seconds per year. The total uptime or the availability of the component can now be described as a string of Nine's as follows: (1-0.00001296/8760) = 0.9999999985 or 99.99999985%.

Since it is awkward to read such a long number, it has become commonplace to count the number of nines, such as "six nines" for 99.9999% or "nine nines" for 99.9999999% availability. In the power-conditioning industry, this method of calculating availability has been used for years to describe how reliable the different premium power systems such as UPS. The concept that was conveyed to the buyers was "the more nines, the more reliable the UPS system."

Even in the digital world of server manufacturers, the metric of Nines was used to tout one product against another. From Compaq to IBM to Hewlett Packard, the number of nines was used as a simple way to convey the reliability of their systems to the user. For example, Hewlett Packard N-Class servers were promoted this way, e.g., "The N-Class offers excellent high availability (99.99% hardware availability, 99.95% across the entire solution stack) as HP moves towards its 5 nines: 5 minutes vision (99.999% data availability with only 5 minutes unplanned downtime per year)."

Recently there has been a trend of using the Nines as a metric for electric power system availability. Simply stated, the number of nines can be easily explained in terms of the percent of time in a year that power is expected to be available, where the 9's are calculated by setting total time as 1 and therefore availability is 1 – the time unavailable. Table 5-4 shows availability, and number of nines for different the average "minutes off" supply. While the technical accuracy of using such an index is subject to interpretation, it may be used to convey, in an order of magnitude, a sense of how much reliability is required by the different customer categories. For example a typical commercial or industrial customer may expect 4 nines, a hospital 6 nines (including its on-site generation), and a data center with elaborate redundant on-site generation and storage systems may be designed for 9 nines.

Table 5-4
Relationship Between Number of Nines and "Minutes Off" Supply

The Standard of Nines	The Number of Nines	Minutes Off Supply
0.99	2 Nines	5256
0.999	3 Nines	525.6
0.9999	4 Nines	52.56
0.99999	5 Nines	5.256
0.999999	6 Nines	0.5256
0.9999999	7 Nines	0.05256
0.99999999	8 Nines	0.005256
0.999999999	9 Nines	0.000526

The difference between the desired power availability for a particular site and the available power service at that site is one way to define opportunities for DR. For example if the desired power availability is 5 nines and the typical service availability is 3 nines, then on-site generation or energy storage is expected to have reliability value.

Reliability of Facility Power Distribution

Reliability of the local power distribution system depends on the electrical components that are critical to power delivery such as service the transformer, circuit breakers, cable, bus duct, and etc. Each component of the power distribution has an expected failure rate and repair time. The IEEE Gold Book is one of the most authoritative resources on reliability of electrical equipment and electric power systems in commercial and industrial facilities. Table 2-5 shows a summary of the failure rates of common equipment as cited in the Gold Book. This reliability data can be used in an analysis to predict local power distribution reliability based on different series and parallel circuit configurations.

Table 5-5
Reliability of Common Low-Voltage (<600 V) Equipment[25]

Equipment	Failure Rate (Events Per Year)	Mean Time Between Failures (Years)
Cable [per 1000 circuit feet]	0.00141	709

[25] IEEE 493-1997 (Gold Book), IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.

Bus duct [per 1 circuit foot]	0.000125	8000
Transformers	0.0062	161
Fixed circuit breakers	0.0042	238
Metalclad drawout circuit breakers	0.0027	370
Enclosed disconnect switches	0.0061	164

Reliability Terminology

commercial power

Electrical power furnished by the electric power utility company, from IEEE Standard 1100-1992. Commercial power is typically referred to as the normal power that is supplied by the incoming feeders. This in some cases may include some portion of generated power from local generators supplied by natural gas, diesel fuel or coal. Generally, the incoming service power is regarded as commercial power when it is connected to the electric power utility feeders regardless of the percentage of power that is supplied by the electric power utility and the percentage supplied by local generation at the end-users location.

connected load

Connected transformer kVA, peak load, or metered demand (to be clearly specified when reporting) on the circuit or portion of circuit that is interrupted. When reporting, the report should state whether it is based on an annual peak or on a reporting period peak, from IEEE 1366, 2004.

customer

A metered electrical service point for which an active bill account is established at a specific location (e.g., premise), from IEEE 1366, 2004.

customer count

The number of customers either served or interrupted depending on usage, from IEEE 1366, 2004.

distribution system

That portion of an electric system that delivers electric energy from transformation points on the transmission system to the customer, from IEEE 1366, 2004.

NOTE—The distribution system is generally considered to be anything from the distribution substation fence to the customer meter. Often the initial overcurrent protection and voltage regulators are within the substation fence and are considered to be part of the distribution system.

failure mode

The effect by which failure is observed, from IEEE STD 100-1992.

This term essentially is the way, or mode, in which the equipment fails. Where some equipment may fail in a destructive mode, where the equipment itself is destroyed, other equipment may fail by ceasing operations. Properly observing the failure mode of equipment enables further clues to be gathered related to the cause of the equipment failure. For example, when an adjustable speed drive has failed, often, the failure mode is recorded in the system electronics, and displayed to the user. The drive may fail for a number of reasons, including low DC bus voltage, high DC bus voltage, improper frequency, etc., where each failure mode typically will correspond to a particular cause of failure or power quality issue.

forced outage

The state of a component when it is not available to perform its intended function due to an unplanned event directly associated with that component, from IEEE 1366, 2004.

interrupting device

An interrupting device is a device whose purpose is to interrupt the flow of power, usually in response to a fault. Restoration of service or disconnection of loads can be accomplished by manual, automatic, or motor-operated methods. Examples include transmission circuit breakers, feeder circuit breakers, line reclosers, line fuses, sectionalizers, motor-operated switches or others, from IEEE 1366, 2004.

interruption

The loss of service to one or more customers connected to the distribution portion of the system. It is the result of one or more component outages, depending on system configuration, from IEEE 1366, 2004. The loss of electric power supply to one or more loads, from IEEE Std 493, 1997.

interruption duration

The time period from the initiation of an interruption to a customer until service has been restored to that customer. The process of restoration may require restoring service to small sections of the system until service has been restored to all customers. Each of these individual steps should be tracked collecting the start time, end time and number of customers interrupted for each step, from IEEE 1366, 2004.

Interruptions caused by events outside of the distribution system:

Outages that occur on generation, transmission, substations, or customer facilities that result in the interruption of service to one or more customers. While generally a small portion of the number of interruption events, these interruptions can affect a large number of customers and last for an exceedingly long duration, from IEEE 1366, 2004.

interruption, forced

An interruption that results from conditions directly associated with a component requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed, or an interruption caused by improper operation of equipment or human error.

NOTE—This definition derives from transmission and distribution applications and does not necessarily apply to generation interruptions.

interruption frequency

The expected (average) number of power interruptions to a load per unit time, usually expressed as interruptions per year, from IEEE Std 493, 1997.

interruption, momentary (power quality monitoring)

A type of *short duration variation*. The complete loss of voltage (<0.1 pu) on one or more phase conductors for a time period between 0.5 cycles and 3s, from IEEE STD 1159-1995.

Momentary interruptions on utility systems are often due to automatic circuit reclosing practices which are employed to clear temporary faults on the power system. With automatic circuit reclosing, a faulted line is de-energized for a short period of time (often referred to as the "dead time") and is then re-energized. The dead time period allows the fault to be cleared and all ionization in the air to dissipate. Practices vary greatly from utility to utility with some utilities employing dead times as short as 12 cycles and others employing dead times of up to 1 minute. When dead times are as fast as the reclosing device will allow, these are typically called instantaneous reclose operations and they usually involve a dead time less than 1 second. Note that many utilities employ dead time sufficiently long that these would cause *temporary* and not momentary interruptions (See: *interruption, temporary*). Other causes of momentary interruptions include mechanical transfer switches (switching a load from one source to another), poor intermittent connections, and faults adjacent to the load which sag the voltage to essentially zero volts (less than 0.1 pu).

interruption, sustained (electric power systems)

Any interruption not classified as a momentary interruption, from IEEE STD 1159-1995.

The decrease of the supply voltage to essentially zero volts (less than 0.1 pu) for a period of time in excess of 1 minute is considered a *sustained interruption*. A sustained interruption is of the category of a long duration voltage variation. Voltage interruptions longer than one minute are often permanent in nature and require manual intervention for restoration. Sustained interruptions are a specific power system phenomena and have no relation to the usage of the term *outage*. Outage, as defined in IEEE-100, does not refer to a specific phenomena, but rather to the state of a component in a system that has failed to function as expected. Also, use of the term *interruption* in the context of power quality monitoring has no relation to reliability or other continuity of service statistics.

interruption, temporary (power quality monitoring)

A type of *short duration variation*. The complete loss of voltage (<0.1 pu) on one or more phase conductors for a time period between 3 s and 1 min, from IEEE STD 1159-1995, see interruption, momentary.

Temporary interruptions are caused by the same general phenomena as momentary interruptions. Table 5-6 provides a description of each of the types of interruption.

Table 5-6
Comparison of the Various Types of Interruptions

Type	Duration
instantaneous interruption	0.5 cycles < $x \leq$ 30 cycles
momentary interruption	30 cycles < $x \leq$ 3 seconds
temporary interruption	3 seconds < $x \leq$ 1 minute
sustained interruption	x > 1 minute

lockout

Refers to the final operation of a recloser or circuit breaker in an attempt to isolate a persistent fault, or to the state where all automatic reclosing has stopped. The current-carrying contacts of the overcurrent protecting device are locked open under these conditions, from IEEE 1366, 2004.

loss of service

A complete loss of voltage on at least one normally energized conductor to one or more customers. This does not include any of the power quality issues such as: sags, swells, impulses, or harmonics, from IEEE 1366, 2004.

major event

Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day (MED), from IEEE 1366, 2004.

major event day

A day in which the daily system SAIDI exceeds a threshold value, TMED. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than TMED are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported, from IEEE 1366, 2004.

mean time between failures (MTBF)

The mean exposure time between consecutive failures of a component. It can be estimated by dividing the exposure time by the number of failures in that period, provided that a sufficient number of failures have occurred in that period, from IEEE Std 493, 1997.

mean time to repair (MTTR)

The mean time to repair or replace a failed component. It can be estimated by dividing the summation of repair times by the number of repairs, and, therefore, it is practically the average repair time. Also it might be referred to as "expected failure duration" referring to expected or long-term average duration of a single failure event. Frequency of system failure is an index of the mean number of system failures per unit time, and is also given as the reciprocal MTBF, from IEEE Std 493, 1997.

momentary interruption

A single operation of an interrupting device that results in a voltage zero. For example, two circuit breaker or recloser operations (each operation being an open followed by a close) that momentarily interrupts service to one or more customers is defined as two momentary interruptions, from IEEE 1366, 2004.

momentary interruption event

An interruption of duration limited to the period required to restore service by an interrupting device, from IEEE 1366, 2004.

NOTE—Such switching operations must be completed within a specified time of 5 min or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or circuit breaker operates two, three, or four times and then holds (within 5 min of the first operation), those momentary interruptions shall be considered one momentary interruption event.

outage (electric power systems)

The state of a component when it is not available to perform its intended function due to some event directly associated with that component, from IEEE 1366, 2004.

NOTES —

(1) An outage may or may not cause an interruption of service to customers, depending on system configuration;

(2) This definition derives from transmission and distribution applications and does not apply to generation outages.

planned interruption

A loss of electric power that results when a component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventative maintenance, or repair, from IEEE 1366, 2004.

NOTES —

(1) This derives from transmission and distribution applications and does not apply to generation interruptions.

(2) The key test to determine if an interruption should be classified as a planned or unplanned interruption is as follows, if it is possible to defer the interruption, the interruption is a planned interruption; otherwise, the interruption is an unplanned interruption.

planned outage

The state of a component when it is not available to perform its intended function due to a planned event directly associated with that component, from IEEE 1366, 2004.

reporting period

The time period from which interruption data is to be included in reliability index calculations. The beginning and end dates and times should be clearly indicated. All events that begin within the indicated time period should be included. A consistent reporting period should be used when comparing the performance of different distribution systems (typically one calendar year) or when comparing the performance of a single distribution system over an extended period of time. The reporting period is assumed to be one year unless otherwise stated, from IEEE 1366, 2004.

step restoration

A process of restoring interrupted customers downstream from the interrupting device/component in stages over time, from IEEE 1366, 2004.

sustained interruption

Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than 5 minutes, from IEEE 1366, 2004.

total number of customers served

The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report, from IEEE 1366, 2004.

transmission company customer

The customers of the transmission system are here considered as being distribution companies, end-customers, and generators.

transmission delivery point

A transmission system Delivery Point is generally the low voltage busbar of the coupling transformer, or the termination of the transmission equipment in the case of lines supplying a customer substation. Where a substation has several busbars that are normally operated separately, each of these is considered a Delivery Point.

unplanned interruption

An interruption caused by an unplanned outage, from IEEE 1366, 2004.

voltage interruption

Disappearance of the supply voltage on one or more phases. Usually qualified by an additional term indicating the duration of the interruption (e.g., *Momentary*, *Temporary*, or *Sustained),* from IEEE STD 1159-1995.

Reliability Indices

Reliability measurement parameters need to include frequency of interruptions, total duration or restoration time, and the number of end users affected. Another way to say this is the number, duration, and severity of events.

System reliability indices have been defined and reported for at least the last 20 years by many US utilities. These indices had their origins in the 70's from reliability engineer's work published by IEEE. However, without any formal standards a lot of variety has been observed in both the indices used, and methods of calculation, among different utility reports. Recently the IEEE Std 1366 has gone a long way toward consistent definition of for these system indices and the methods for calculating them.

Even with the new standard there are some aspects of reporting where more work is needed in defining and establishing consensus. For example there is not agreement on the definition of major events and on a single way to calculate outage indices when major events occur. Consequently the IEEE working group on outage reporting practices continues its standardization activity in this area.

In order to fully define the performance of the system, indices are required that define the following performance areas:

- How often the system is interrupted (momentary and sustained events separately)
- The duration of sustained interruptions (system index for all delivery points)
- The restoration time for sustained interruption (i.e. the duration of interruptions seen by the affected delivery points)
- The severity of interruptions experienced on the system (load affected)
- The availability of the circuits that make up the system
- The number and severity of unplanned load reduction events

Traditional Utility Distribution Reliability Indices

In IEEE 1366 nine indices are defined, however based on a survey of US utilities, only 4 are in common use. The two most commonly used indices based on sustained interruptions are the Service Average Interruption Frequency Index (SAIFI) and Service Average Interruption Duration Index (SAIDI). Also popular for sustained interruptions are indices on Customer Average Interruption Duration (CAIDI) and Average Service Availability (ASAI) is for momentary interruptions the most commonly used index is Momentary Average Interruption Frequency Index (MAIFI). The following are the definitions of these indices from IEEE 1366.

SAIFI System average interruption frequency index (sustained interruptions). This index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area. In words the definition is:

$$SAIFI = \frac{Total\ number\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served} \qquad \textbf{Eq. 5-1}$$

To calculate the index use the following equation:

$$SAIFI = \frac{\sum N_i}{N_T} \qquad \textbf{Eq. 5-2}$$

SAIDI System average interruption duration index. This index is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information about the average time the customers are interrupted. In words, the definition is:

$$SAIDI = \frac{\sum Customer\ interruption\ durations}{Total\ number\ of\ customers\ served} \qquad \textbf{Eq. 5-3}$$

To calculate the index, use the following equation:

$$SAIDI = \frac{\sum r_i N_i}{N_T} \qquad \textbf{Eq. 5-4}$$

CAIDI Customer average interruption duration index. CAIDI represents the average time required to restore service to the average customer per sustained interruption. In words, the definition is:

$$CAIDI = \frac{\sum \text{Customer interruption durations}}{\text{Total number of customer interruptions}} \qquad \textbf{Eq. 5-5}$$

To calculate the index use the following equation:

$$CAIDI = \frac{\sum r_i N_i}{N_T} = \frac{SAIDI}{SAIFI} \qquad \textbf{Eq. 5-6}$$

ASAI Average service availability index. This index represents the fraction of time (often in percentage) that a customer has power provided during one year or the defined reporting period. In words, the definition is:

$$ASAI = \frac{\text{Customer hours service availability}}{\text{Customer hours service demand}} \qquad \textbf{Eq. 5-7}$$

To calculate the index use the following equation:

$$ASAI = \frac{N_T \text{ x } (\text{No. of hours/year}) - \sum r_i N_i}{N_T \text{ x } (\text{No. of hours/year}} \qquad \textbf{Eq. 5-8}$$

System indices for reporting momentary outages were also introduced in the IEEE Std 1366. In the past many short-term outage were not reported. These are of particular consequence when determining service reliability for digital or highly automated process industries, where a very short interruption has about the same impact on the process as a sustained outage. The most used of the momentary outage indices is MAIFI.

MAIFI Momentary average interruption frequency index. This index is very similar to SAIFI, but it tracks the average frequency of momentary interruptions. In words, the definition is:

$$MAIFI = \frac{\text{Total number of customer momentary interruptions}}{\text{Total number of customers served}} \qquad \textbf{Eq. 5-9}$$

To calculate the index, use the following equation:

$$MAIFI = \frac{\sum ID_i N_i}{N_T} \qquad \textbf{Eq. 5-10}$$

A survey by Edison Electric Institute (EEI), in 1995 has been useful in showing how utilities are using indices. In this survey 160 utilities were survey and 78 responded. These results are shown in Figure 5-1.

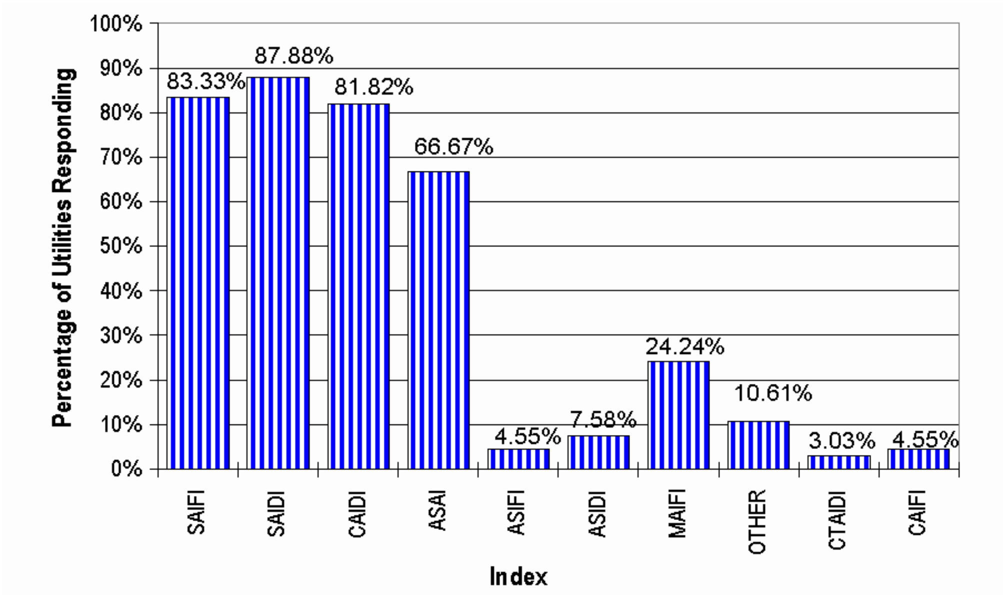


Figure 5-1
Percentage of Companies Using Indices Reporting in 1995[26] Out of 78 Utilities

The most used index is SAIDI, followed by SAIDI and CAIDI. Many utilities also measure ASAI, which represents the fraction of time (often in percentage) that an end-user has power available during one year or other defined reporting period. For example, if an end-user does not have power for a total of 2 hours in a given year (8,760 hours), the ASAI index for that customer is calculated as ASAI =(8760-2)/8760 = 0.99977. So ASAI can be described as the number of nines or a percentage representing actual availability.

In the 1995 EIA survey, with 78 utilities reporting, the average feeder availability reported was to be .9994 and the mean was .9998. Some exceptional feeders reported 5 and 6 nines availability. This was also true in an earlier survey in 1990 with 60 utilities responding. For some transmission-connected customers availability is reported at 100%, which means that the power is available for all 8,760 hours a year.

However availability one, the number of 9s, is not always the best measure of perceived reliability. This is the reason for the new momentary measures of reliability. It is certainly possible to have many momentary interruptions and a 3 or 4 nines of availability. Figure 5-2 shows the survey result for the momentary, MAIFI, index. It should be noted that a severe

[26] A Nationwide Survey of Distribution Reliability Measurement Practices" By IEEE/PES Working Group on System Design, Paper No.98 WM 218

voltage sag, which may result in a end-user equipment interruption, is not counted in the MAIFI index.

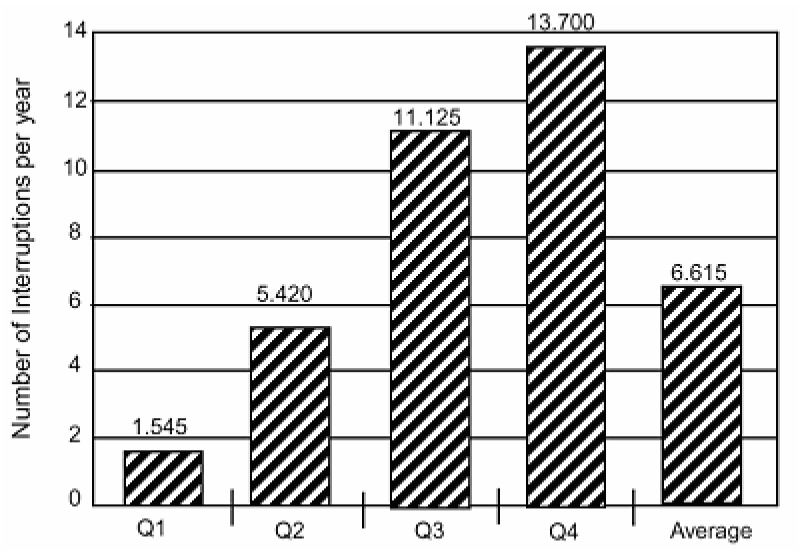


Figure 5-2
Results of Survey of MAIFI Index for Reliability

Summary of Common Transmission Indices

Indices used for transmission interruption reporting differ significantly from utility to utility. The indices used can however be divided into the following categories:

- **Number of events:** *actual number of events* and *the average number of events* over the reporting period (i.e. the latter is the average frequency of events)
- **Duration of events:** *average total duration of events* over the reporting period and *average time to restore supply per interruption* at each supply point. The *availability of the supply* is the converse of the duration and it gives an indication of the relative risk of interruptions
- **Severity of events:** *severity of the interruption events* over the reporting period (i.e. the size of load affected) and indices estimating the *cost impact per event*

Average Frequency of Event Indices

Examples of indices in each of these categories that are in use around the world are summarized in the following:

Number of supply interruptions (Australia): The number of supply interruptions is defined as a measure of the number of interruptions to customers due to failure to provide transmission services, *including single phase and multi-phase trip operations* [25].

Number of loss of supply incidents (UK - National Grid, OFGEM): System events that result in a single or multiple loss of supply. Incidents are reported individually with details of location, time, incident duration, maximum demand lost, and an estimate of the energy not supplied [26]. Anomalous events (see below) are included in the reported figures. Note here that one reported incident may relate to several customers being affected.

Number of loss of supply incidents - anomalous events (UK - National Grid, OFGEM): Interruption events, which arise as a result from particular connection or running arrangements chosen by customers or from other causes, which are not due to NGC equipment. These are also included in the total number of loss of supply incidents, but are specifically identified.

Average interruption frequency indices define the average number of events seen per delivery point or customer supply point.

System average interruption frequency index - SAIFI: The ratio of the number of delivery point interruptions to the number of delivery points.

System average interruption frequency index - SAIFI (Cigre WG 39.04 definition): The quotient of the number of interruptions and the number of *delivery and/or reception points* [27]

System average interruption frequency index for momentary interruptions - SAIFI-MI (Canada): A measure of the average number of momentary (less than one minute) interruptions that a delivery point experiences during a given year.

System average interruption frequency index for sustained interruptions - SAIFI-SI (Canada): A measure of the average number of sustained (greater than one minute) interruptions that a delivery point experiences during a given year.

Transmission sustained and momentary average interruption frequency index - TSMAIFI (USA): Average interruption frequency including momentary and sustained interruptions.

Average Event Duration and Restoration Time Indices

System average interruption duration - SAIDI: A measure of the average total interruption duration that a delivery point experiences during a given year.

System average interruption duration - SAIDI (Cigre WG 39.04 definition): A measure of the average total interruption duration that a *delivery and/or reception point* experiences during a given year.

Customer interruption duration index - CI (Canada): Some utilities report a customer interruption duration index defined as:

$$CI = \frac{\text{Sum of customer hours interrupted}}{\text{sum of all customers}} \quad \textbf{Eq. 5-11}$$

This index is derived considering the duration of forced interruptions, planned interruptions and short interruptions (< 1 min).

Average incident duration (UK): The average *incident* duration is defined by National Grid (UK) as:

$$\frac{\text{Estimated Total Energy Unsupplied (MW minutes)}}{\text{Total of MW Lost}} \qquad \textbf{Eq. 5-12}$$

Average interruption time (UNIPEDE): A survey based on average interruption time made use of the following definition for this measure [28]:

$$AIT = \frac{8760.60.ENS}{AD} \text{ (min / year)} \qquad \textbf{Eq. 5-13}$$

where

ENS is defined as the energy not supplied due to interruptions with network losses excluded (MWh/year) and

AD is the annual demand for the power system with network losses excluded (MWh/year).

Average interruption restoration indices describe the average restoration time per interruption per deliver point.

System average restoration index - SAIRI: A measure of the average duration of a delivery point interruption. It represents the average restoration time for each delivery point interruption.

System average restoration index - SAIRI (Cigre WG 39.04 definition): The quotient of the interruption duration and the number of delivery and/or reception point interruptions.

Interruption Severity and Cost Indices

Interruption severity indices aim at describing the size of the load affected, and is usually based on the energy not supplied as a function of the overall size of the system.

Energy not supplied (UK - National Grid, OFGEM): Estimated energy (MWh) not supplied during the year.

Interruption severity index (UNIPEDE): A UNIPEDE survey on transmission and sub-transmission interruption performance defined an interruption severity index as follows:

$$SI = \frac{ENS.(10)^5}{AD} \quad \text{(pu)} \qquad \textbf{Eq. 5-14}$$

ENS is defined as the energy not supplied due to interruptions with network losses excluded (MWh/year) and

AD is the annual demand for the power system with network losses excluded (MWh/year).

System minutes (UNIPEDE): A UNIPEDE survey on transmission and sub-transmission interruption performance defined a system minute index as:

$$SM = \frac{ENS..60}{PL} \quad \text{(min / year)} \qquad \textbf{Eq. 5-15}$$

ENS is defined as the energy not supplied due to interruptions with network losses excluded (MWh/year), and

PL as the peak load of the year (MW).

System minutes (Cigré): A system minute index is defined by Study Committee 26 as:

$$SM = \frac{ENS..60}{MSD} \qquad \textbf{Eq. 5-16}$$

ENS is defined as the energy not supplied due to disturbance (MWh), and

MSD as the Maximum System Demand met to date.

System minutes (Australia-SAIIR): The system minute index (SM) used to report transmission interruption performance in Australia is defined as:

$$\text{SM} = \frac{\sum \text{MW Interrupted} \times \text{duration in minutes}}{\text{System Maximum Demand}} \qquad \textbf{Eq. 5-17}$$

MW Interrupted is defined at the estimated MW of the load that was interrupted for a total time of duration in minutes. *System Maximum Demand* is defined as the maximum amount of electricity (MW) generated by generators situated in South Australia, and delivered into South Australia via any interconnection between the South Australian electricity network and the electricity network of another State at any time prior to the commencement of the relevant reporting period. It includes energy not supplied to customer as a result of forced outages and unplanned outages caused by faults.

Interruption cost index (Norway): The Norwegian electricity regulator (NVE) has recently adopted an "interruption cost" (IC) index defined as [29]:

$$IC = \sum_{m,n} ENS_{m,n} . c_{m,n}$$ **Eq. 5-18**

ENS is the energy not supplied, *c* the average cost per customer category (dependent on notification),

n the customer category, and

m the notified vs. un-notified interruptions. The average cost per customer category is fixed annually by the regulator (NVE). The index applies to events that result in an interruption duration of longer than 3 min, all incident types (i.e. both planned and unplanned interruptions) and is applied for all interruptions at network voltages greater than 1kV.

Future Transmission System Indices

The indices proposed below should be applied for reporting unplanned events.

Delivery Point Interruption Frequency

SAIFI-MI: the system average interruption frequency - momentary interruptions.

SAIFI-SI: the system average interruption frequency - sustained interruptions.

Delivery Point Interruption Duration

SAIDI: the average duration of (sustained) interruptions for all delivery points.

SAIRI: the system average (sustained) interruption restoration time for customers' delivery points experiencing interruptions

NOTE: SAIRI can be derived by dividing SAIDI by SAIFI-SI.

System Interruption Severity

System Minutes - Degree of Severity: Number of events in each of the categories of severity 0 to 3 (see Table 5-7 below).

System Minutes < 1: Cumulative system minutes for all Bulk Electricity System (BES) events of severity less than 1 system minute

System Minutes > 1: Cumulative system minutes for all Bulk Electricity System (BES) events of greater or equal to 1 system minute

MW.Minutes - Degree of Severity: Number of events in each of the categories of severity 0 to 3 (see Table 5-7 Below) for local significant interruptions.

Table 5-7
System Minutes and Local Severity Measures

Degree Severity	Description	BES (SM)	Local (MW.min)
0	Unreliability condition normally considered acceptable	<1	<1000
1	Significant impact on one or more customers but not considered serious, impact less than 10 times that of acceptable	1-0	1000-9999
2	Serious impact on customers, impact considered 10 to 100 times than acceptable	10-99	10000-99999
3	A very serious impact on customers, impact considered more than 100 times than acceptable	>=100	>=100000

In some cases a customer may have an agreement to shed load (interruptible contract). If the load reduction incident is within the duration and number of events agreed in such a contract, this may be considered as a planned load reduction incident.

This index provides an important indication of the level to which the system is able to respond to problems with the transmission system - or with the generators. It is likely to be an important measure for all stakeholders in the new industry. This measure may be affected by the transmission system operator, the Transmission wires company, or by generation. The decisions by the transmission system operator on reserve margins will determine the extent to which generation loss will affect this index. In some countries the system operator and the wires business are separate entities.

Transmission System Circuit Availability

The proposed index defining the availability of a transmission entity's transmission circuits to provide transmission services is defined follows:

The number of unavailable circuit hours is defined, in relation to each circuit in a transmission entity's transmission network, the number of hours during each reporting period in relation to which that circuit is unavailable to provide transmission services (excluding outages requested by a distributor or a transmission customer but otherwise including all planned outages and unplanned outages in relation to the trans-mission entity's transmission network). The total number of circuits is defined as the total number of circuits comprised in a transmission entity's transmission network.

Distribution System Interruption Reporting Indices

IEEE 1366-2003 provides the most up-to-date reference for distribution system reliability indices. The proposed indices from the CIGRE C4.07/CIRED Working Group are listed here and the reader is referred to IEEE 1366 documents for additional descriptions.

Delivery Point Interruption Frequency

SAIFI-SI: the average number of sustained interruptions experienced by distribution customers

Interruption Duration

SAIDI: the total duration of interruptions experienced by the average distribution customers

CAIDI: the average time to restore service to customers affected by interruptions

Cigre Working Group

Although the Cigre report provided no measurement data for individual sites, indices used by different companies for tracking reliability levels are included in Table 5-7.

In addition, the following reports provide reliability levels information from other surveys:

1. Second Benchmarking Report on Quality of Electricity Supply, Working Group on Quality of Electricity Supply, Council of European Regulators, September, 2003.
2. *Distribution Reliability Indices Tracking Within the United States*, EPRI, Palo Alto, CA: 2003. 1008459.
3. Second Benchmarking Report on Quality of Electric Supply, Council of European Regulators.

Within the working group of the Council of European Regulators, seven countries reported time-series data for Unplanned Interruptions for the three years, 1999-2001. Data for the year 2001 is also available for Portugal and Spain.

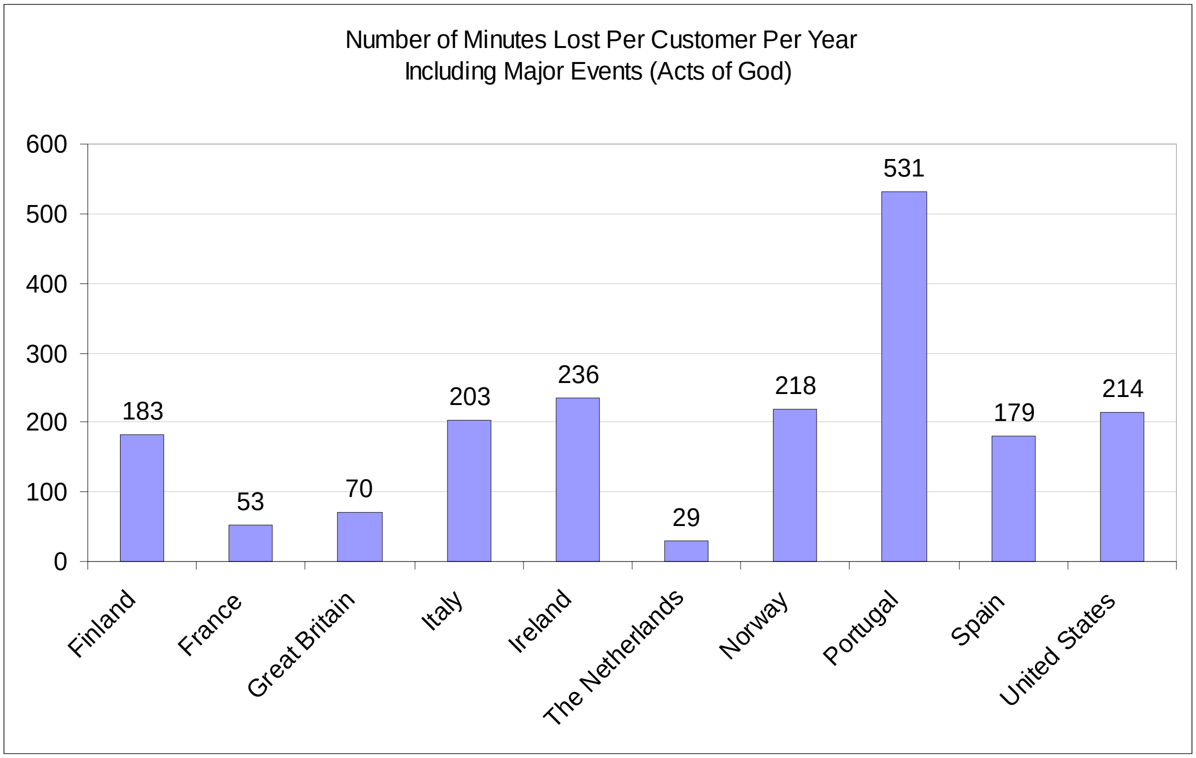


Figure 5-3
Number of Minutes Lost per Customer per Year Including Major Events

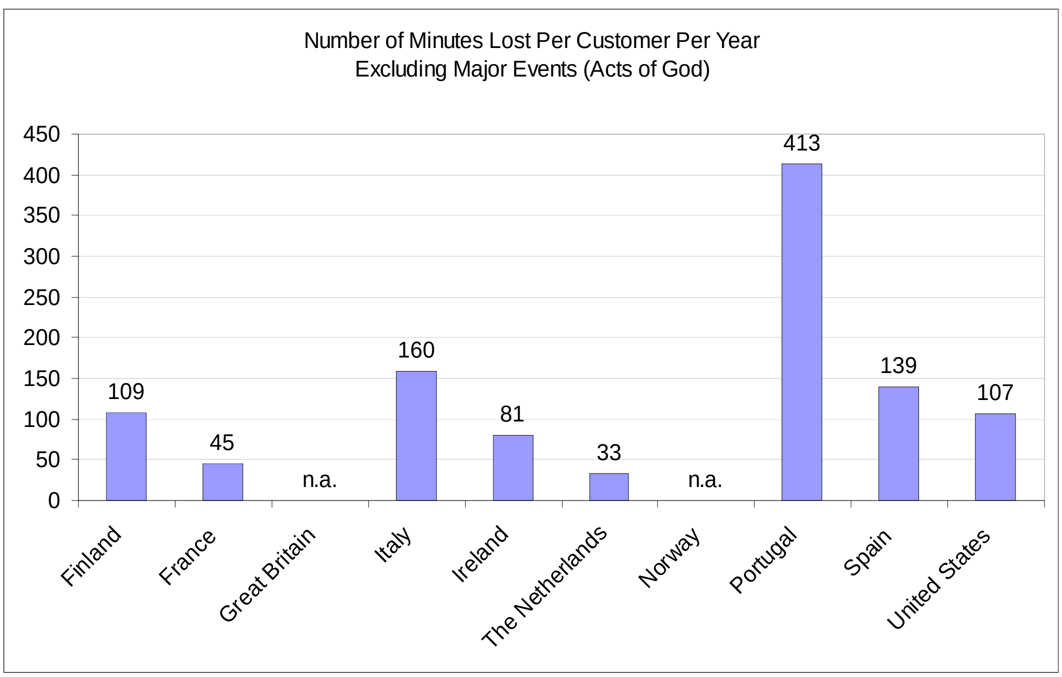


Figure 5-4
Number of Minutes Lost per Customer per Year Excluding Major Events

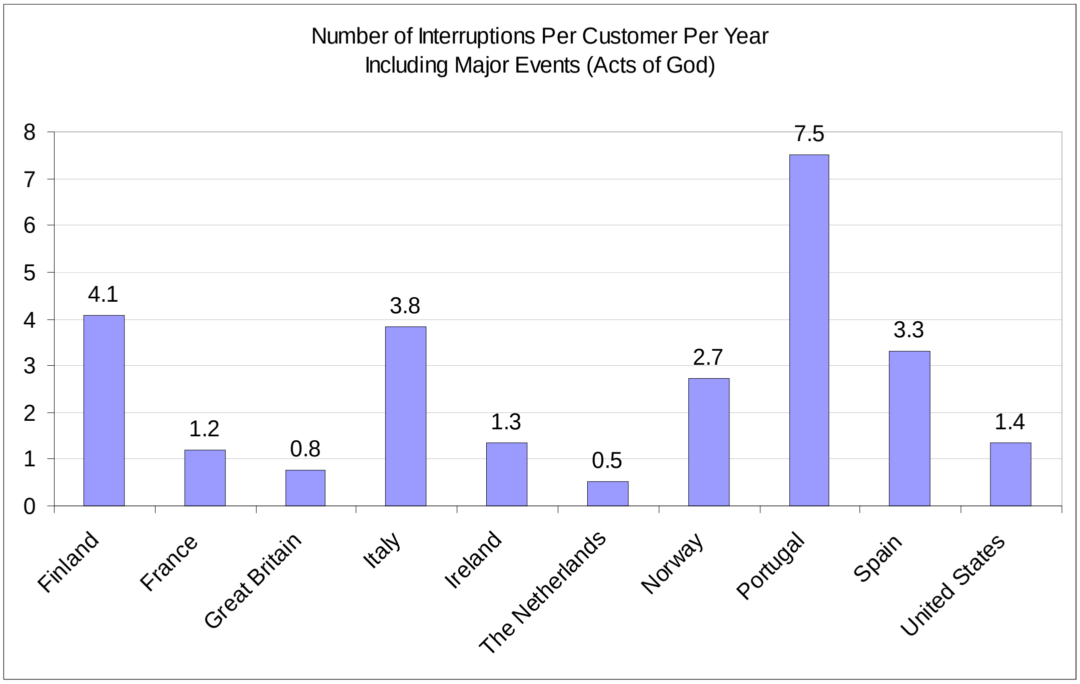


Figure 5-5
Number of Interruptions per Customer per Year Including Major Events

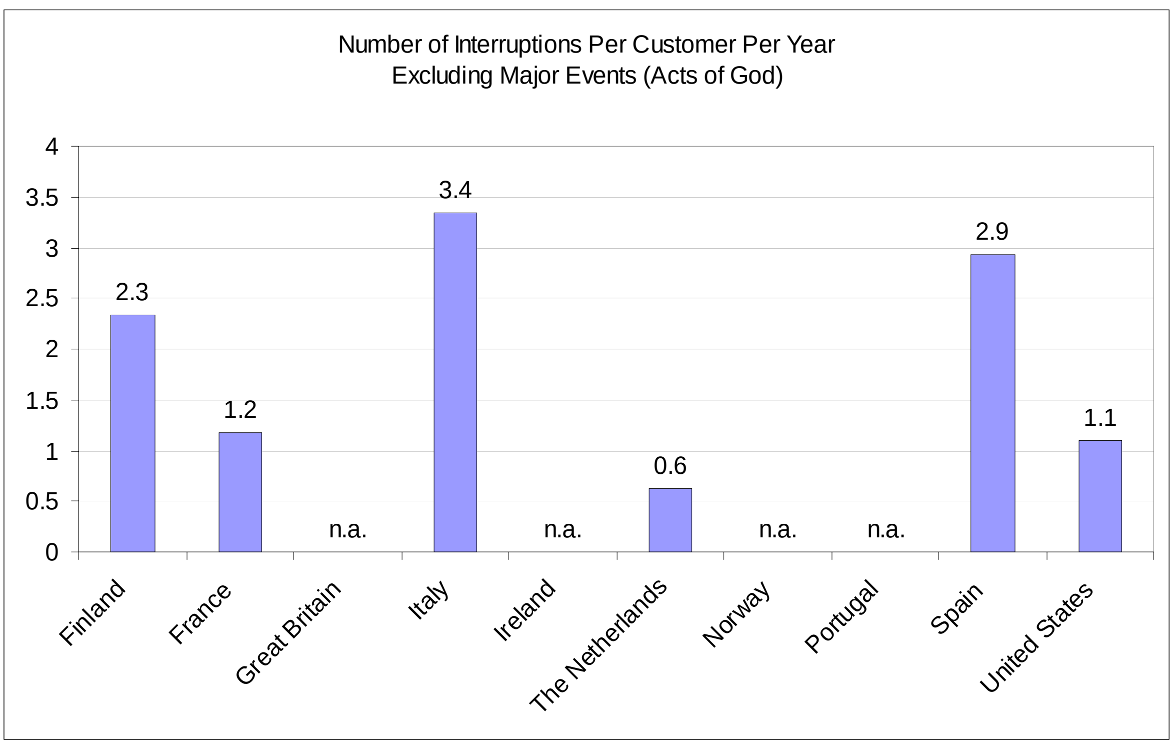


Figure 5-6
Number of Interruptions per Customer per Year Excluding Major Events

EPRI Report on Distribution Reliability Reporting in the United States

The following figures provide more detail based on reported reliability indices for Distribution in the United States and is based upon *Distribution Reliability Indices Tracking Within the United States*, EPRI, Palo Alto, CA: 2003. PID 1008459.

Figure 5-7 below shows the 10-year trend of the lower quartile (25^{th} percentile), median (50^{th} percentile) and upper quartile (75^{th} percentile) for annual SAIDI values for the different utilities in the United States. Since there is limited data available for the early years (1992–1996) the trend analysis focuses on the last five years (1997–2001) data. During this time period there is no indication of an upward or a downward trend for the median value of SAIDI over time. The 75^{th} percentile (upper quartile) of the SAIDI value showed an increasing trend during the 1998–2000 period, which was reversed in 2001. During the time the data was collected for this project, information for 2002 was not yet available to validate whether the decreasing trend was a sustaining downward trend lasting beyond a single year.

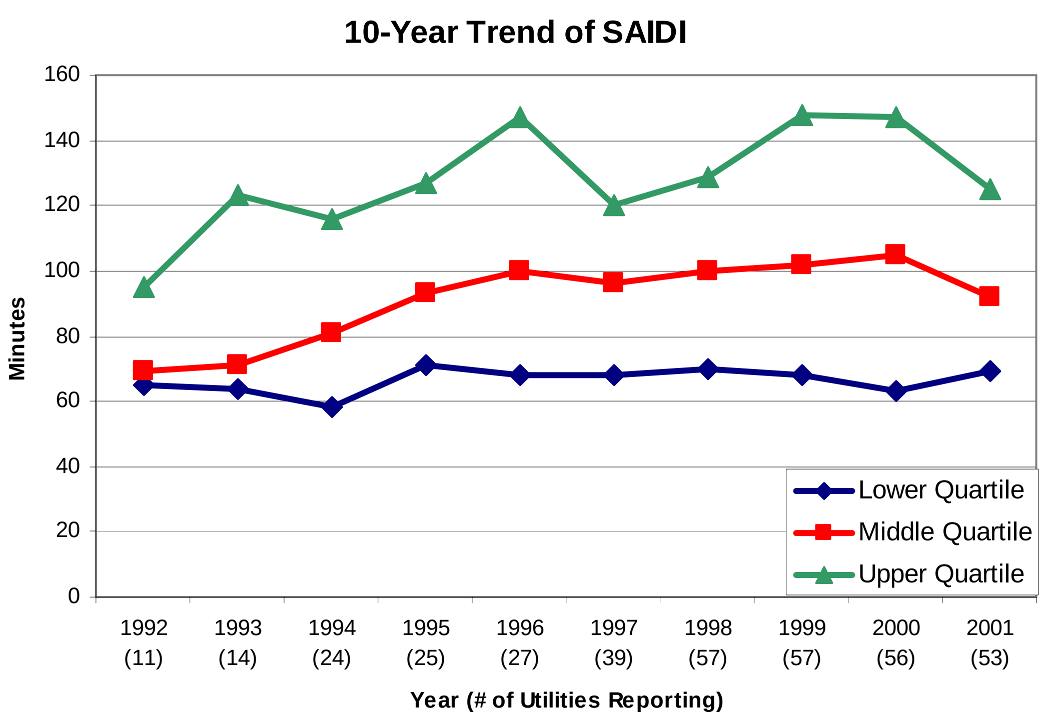


Figure 5-7
Ten-Year Trend In SAIDI Interruption Minutes (Lower, Middle, and Upper Quartile)

Figure 5-8 below provides a 10-year trend of the lower quartile (25th percentile), median (50th percentile) and upper quartile (75th percentile) for SAIFI values reported. Since there is limited data available for the early years (1992-1996) the trend analysis focuses on the last five years (1997-2001). During this time period there is no indication of an upward or a downward trend for the lower quartile value of SAIFI for each year. The 75th percentile (upper quartile) of the SAIFI value showed a decreasing four-year trend from 1998 through 2001. The median value of SAIFI shows an increasing trend from 1998 to 2000, which was reversed in 2001. During the time the data was collected, 2002 information was not yet available to validate whether the decreasing trend was only temporary or a sustaining downward trend.

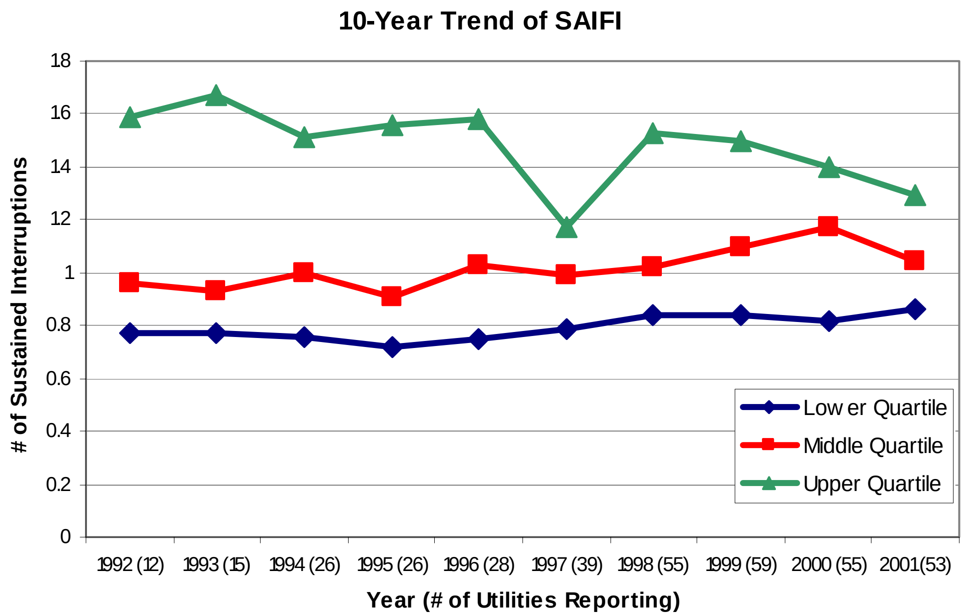


Figure 5-8
Ten-Year Trend In SAIFI Number of Sustained Interruptions (Lower, Middle, and Upper Quartile)

Combining Site Indices to Calculate System Indices

System indices are used by the network operator to assess the performance of a whole system. They can be used to compare year-to-year performance, where the effect of weather variations should also be considered. The results of such a performance assessment or comparison can be used as a basis for improvements in the system. The indices are not a benchmark by which to judge different networks against each other but can be used to identify typical levels of disturbances for various types of network and for ongoing monitoring of any one network. Differences in geography, climate, load density, and system design make comparisons of system indices for different systems of little value.

System indices are calculated from the site indices of all monitored sites over a certain region. A region may consist of the network operated by one company, one voltage level, one country or province, etc.

System indices for voltage dips can be presented in the same way as site indices. The required level of detail is typically lower for system indices than for site indices. The choice of bins should represent typical fault-clearing times, other system properties, and typical equipment susceptibility, depending on the application. Different sets of system indices can be calculated for significant portions of the system with different characteristics (i.e. transmission and distribution, urban and rural, etc.).

System indices can be calculated based on average values for the site indices or based on levels that are not exceeded for 95% of the sites. Weighting factors can be introduced to account for important characteristics of the individual sites (e.g. number of customers, load, etc.).

It is recommended for system indices that voltage dip measurements use the phase-to-phase voltages because they give a better statistical representation of what end-use equipment would actually see. If line-to-neutral voltages are measured, it may be possible to calculate line-to-line voltages for purposes of indices calculation.

Full coverage can only truly be obtained if 100% of all sites are being monitored. However by recognizing the primary influencing factors and then considering site categorization it should be possible to install monitors in a targeted way such that it is possible to cover all categories of sites. The results for each category can then be mapped on to non-monitored sites, with a verification based on known fault statistics.

6
AVAILABILITY

As applied in electric power systems, the term availability simply means how much of the total time of interest the power is available. Availability is usually stated as a percentage. For example, a power system that is down for a total of 60 minutes each year would be said to be 99.98% availability. If the same power system failed 3 times in that year then the mean-time between-failures would be very close to 4 months. Availability and reliability are closely related in that each is a measure of time (or percentage of time) that a process is up and running. Availability, however, is more dependent on the time after a process is interrupted and reliability is more dependent of the time between process interruptions.

Attributes of Power System Availability

Most quantifications of the availability of electrical supply have included only long-duration interruptions. Most utilities only track interruptions that are greater than 5 minutes. A realistic barometer of the reliability of the electrical supply should include short-duration power quality events. However, it is very difficult to include power quality disturbances with availability because availability is heavily weighted towards long-duration events.

The rate of interruptions of the electric supply is often quantified in terms of the mean time between failures (MTBF). The *failure rate* is denoted by λ in units of average number of failures per unit of time (λ =1/MTBF).

The availability index does not naturally consider power quality effects. One way to make the availability include short-duration events is to apply a minimum recovery period. If an event occurs that is classified as a “disturbance,” the interruption duration is taken as the disturbance period plus the recovery period. If another event occurred before the recovery period was over, the duration is the time from the first event to the last event plus the recovery period. When the recovery period is over, everything resets. The recovery period should be taken as something “typical” for the “lost productivity time.” For example, for a time window of 15 minutes, a voltage sag exceeding some criteria (such as the ITIC curve, established by the Information Technology Industry Council) would count as a 15-minute interruption. Effectively, so would a one-second momentary (actually 15 minutes plus one second). A sag followed two minutes later by a momentary would count as a 17-minute duration (15 + 2 + minor time for the sag and momentary). This helps to include short-duration events.

An important part of maintaining high availability involves optimizing equipment maintenance. Traditional maintenance practices for power delivery equipment rely heavily on routine inspection and overhauls, which are often driven by manufacturer recommendations or utility customs. Such an approach can lead to errors, which result in unnecessary maintenance costs and degraded availability and reliability. A more cost-effective approach known as Reliability Centered Maintenance (RCM) sets maintenance tasks at intervals based on data that reflect actual equipment condition. Extending this existing concept, "living RCM" will allow for continuous maintenance re-evaluation based on power delivery operation and maintenance "feedback" and timely adjustments to reflect changes in operating conditions, failure mechanisms, age of equipment, and effectiveness of maintenance programs and procedures. Benefits of this approach include improved reliability and availability of power delivery equipment by performing continuously adjusted maintenance based on the reliability of critical equipment and the effectiveness of past maintenance programs.

Availability for sensitive digital processes acknowledges that over the course of a year there is a difference between a single one-hour electric power interruption and sixty one-minute interruptions. Since both these cases have 60 minutes of cumulative outage, the calculation of power availability would be the same. However, the calculation of an end-user's process availability is likely to be different as it considers the time required to affect repairs and get things up and running again. As a result very high power availability may have poor reliability because of the number of upsets and poor process availability because of the cumulative time to restore the process after a large number of short time events.

For example, if 30 minutes were required to restart a sensitive digital process after an electric power interruption, availability of the digital process in the case of a single one-hour outage per year would be 99.98%. However, Availability of the process drops to 99.64% (over 31 lost hours per year) when subjected to 60 one-minute outages and restarts per year. Again, achieving availability levels above 99.98% typically requires significant augmentation with new technologies and techniques, and today's options are often costly and require added maintenance. New, innovative solutions, comprising the whole of the power delivery and end-use process, are needed. Various levels of Availability used in the data-handling industry are shown in Table 6-1.

Table 6-1
Levels of Availability (Source: Sun Microsystems)

System Type	Unavailability (Minutes/Year)	Availability (Percent)	Availability Class
Unmanaged	50,000	90	1
Managed	5,000	99	2
Well-Managed	500	99.9	3
Fault Tolerant	50	99.99	4
Highly Available	5	99.999	5
Very Highly Available	0.5	99.9999	6
Ultra Highly Available	0.05	99.99999	7

In modern business today we often hear the metric Six-Sigma or 6 standard deviations from the mean as an important measure of process performance and quality. Many electric customers are striving for perfection in their business processes. The six-sigma objective sets a target of 3.4 defects out of 1,000,000 results or opportunities. Higher sigma means fewer defects. And one of the most important concepts in achieving a high sigma success rate in a process is to reduce the process variance. Mathematically variance is the square of standard deviation, so decreasing process variation reduces the number of defects and increases the process sigma.

In the power delivery industry availability, measured in terms of 9's, has become more or less an equivalent to the 6-sigma objective. And six-9's, or 99.9999%, of power available is often cited as an objective for mission critical facilities. In fact six-9's is actually better performance than 6-sigma since the deviation or failure rate is 1 part per million compared to 3.4 parts per million. The typical utility service in the US is approximately 99.95%, which equates to a sigma of about 4.8. Clearly, by this measure, the reliability of power delivery in the US is very good.

Availability in the conventional terms of a power system reliability calculation is the expected "up time" of a component or system. It is based on both its mean-time-between-failures (MTBF) and mean time to repair (MTTR). For example, if the MTBF of a switchgear is 0.0012 failures per year ( ) and if the MTTR is 10 hours (r), then the total downtime you would expect from the component is a product of and r, or 0.0012 X 10 = 0.012 hours, an "unavailability" of .72 minutes per year. The availability, or up time, of the component can now be described as a string of nine's as follows: (1-0.012/8760) = 0.99999863 or 99.999863%.

Since it is awkward to read such a long number, it has become commonplace to count the number of nines, such as "six nines" for 99.9999% or "nine nines" for 99.9999999% availability. In the power-conditioning industry, this method of calculating availability has been used for years to describe how reliable the different premium power systems such as UPS. The concept that was conveyed to the buyers was "the more nines, the more reliable the UPS system."

Even in the digital world of server manufacturers, the metric of Nines was used to tout one product against another. From Compaq to IBM to Hewlett Packard, the number of nines was used as a simple way to convey the reliability of their systems to the user. For example, Hewlett Packard N-Class servers were promoted this way, e.g., "The N-Class offers excellent high availability (99.99% hardware availability, 99.95% across the entire solution stack) as HP moves towards its 5 nines: 5 minutes vision (99.999% data availability with only 5 minutes unplanned downtime per year)."

Recently there has been a trend of using the Nines as a metric for electric power system availability. Simply stated, the number of nines can be easily explained in terms of the percent of time in a year that power is expected to be available, where the 9's are calculated by setting total time as 1 and therefore availability is 1 – the time unavailable. Table 5-4 shows availability, and number of nines for different the average "minutes off" supply. While the technical accuracy of using such an index is subject to interpretation, it may be used to convey, in an order of magnitude, a sense of how much reliability is required by the different customer categories. For example a typical commercial or industrial customer may expect 4 nines, a hospital 6 nines (including its on-site generation), and a data center with elaborate redundant on-site generation and storage systems may be designed for 9 nines.

Table 6-2
Relationship Between Number of Nines and "Minutes Off" Supply

The Standard of Nines	The Number of Nines	Minutes Off Supply
0.99	2 Nines	5256
0.999	3 Nines	525.6
0.9999	4 Nines	52.56
0.99999	5 Nines	5.256
0.999999	6 Nines	0.5256
0.9999999	7 Nines	0.05256
0.99999999	8 Nines	0.005256
0.999999999	9 Nines	0.000526

The difference between the desired power availability for a particular site and the available power service at that site is one way to define opportunities for power system improvement. For example if the desired power availability is 5 nines and the typical service availability is 3 nines, then on-site generation or energy storage is expected to have reliability value.

Availability of Utility Electric Service

The availability of electricity from U.S. utilities varies significantly from region to region. It is also different in urban, suburban, and rural areas. The number of outages depends upon the length of the distribution circuit, whether it is underground or overhead, its voltage class, and so on. In an area served by an underground low-voltage distribution network, electric customers may experience less than one interruption every 10 years. And, in some rural areas served by long overhead distribution circuits of radial design, the cumulative outage time may be counted in days per year. Still the vast majority of utility customers have come to expect an electrical outage rate that is well below 10 hours per year—the availability normally exceeds 99.9% and often approaches 99.99%.

Compared to most local generation options, the utility electric service reliability is excellent. A rough estimate of expected utility electric availability can be obtained by looking at the way the service is provided. Average electric service reliability is well known as a function of feeder type. Based on the Nines method and using approximate values (because the difference in availability demarcated between any two consecutive Nines can be large), the availability of electric supply for the different categories of feeders is typically:

- Commercial Business District: 99.999%
- Urban: 4 Nines or 99.99%
- Rural: 3 to 4 Nines or 99.9% to 99.99%
- Remote: 3 Nines or 99.9%

Note that these are average numbers for a large number of feeders. Any particular customer on any given circuit may experience reliability that is higher or lower than the numbers shown above. It is always best to look at feeder specific data when the location is known.

Also it is important to note that availability is only one measure of reliability. In some practical cases a very high availability is not considered to be reliable service because the frequency of occurrence of events is relatively high. In this case availability can remain high if all events are of short duration, e.g. momentary. The unreliability comes in situations where brief power interruptions translate into longer down time of end use process or equipment. To better communicate these differences in interruption duration several classifications have been established in power system standards.

Depending on which standard is followed, power failures or interruptions have been classified as long-term, short-term, momentary, temporary or sustained. Although impacts on the end user may vary, depending on the nature of the load equipment, and critically of its function, the times associated with these terms are becoming more standardized, especially in the utility industry. These standard terms can be a big help in communicating power-related problems with end users, see reliability terminology.

Availability of Local Generation

The availability of the electric grid is typically 99.9 or 99.99. By comparison a local internal combustion generator in continuous operation is *available approximately 95 to 97% of the time*. At 97% availability this means that the local generator is expected to be out of service 263 hours a year, which is about 11 days. Most generator equipment manufactures cannot guarantee this level of availability and field date shows a range of from 88 to 98%, see Figure 6-1.

Some downtime is planned to perform maintenance; these outages may not impact the end user if they can be scheduled at non-critical times. However, generators are also out of service because of unplanned events about 1 to 2% of the time, or 88 hours per year, a little over three and a half days. Since this level of reliability is less than that of typical utility service, a transfer or paralleling scheme is needed. These reliability figures discussed are for a single local generator and can be improved with multiple units and redundant capacity.

Facilities can also employ grid-connected generation to meet local needs for power along with supplying reliability enhancement. The installation costs are similar to backup generation, but the economics are much different as fuel costs and possible cogeneration benefit are factored in. For grid-connected generation, the availability is the key performance indicator as it affects the reliability to the load. A typical generator availability is likely to be much lower than the availability of typical electric utility service. Given the lower availability, it is difficult to supply highly reliable power solely with local generation (without the utility). Assuming that an individual generator has 97% availability the number of generators needed to achieve a specified system reliability can be calculated.

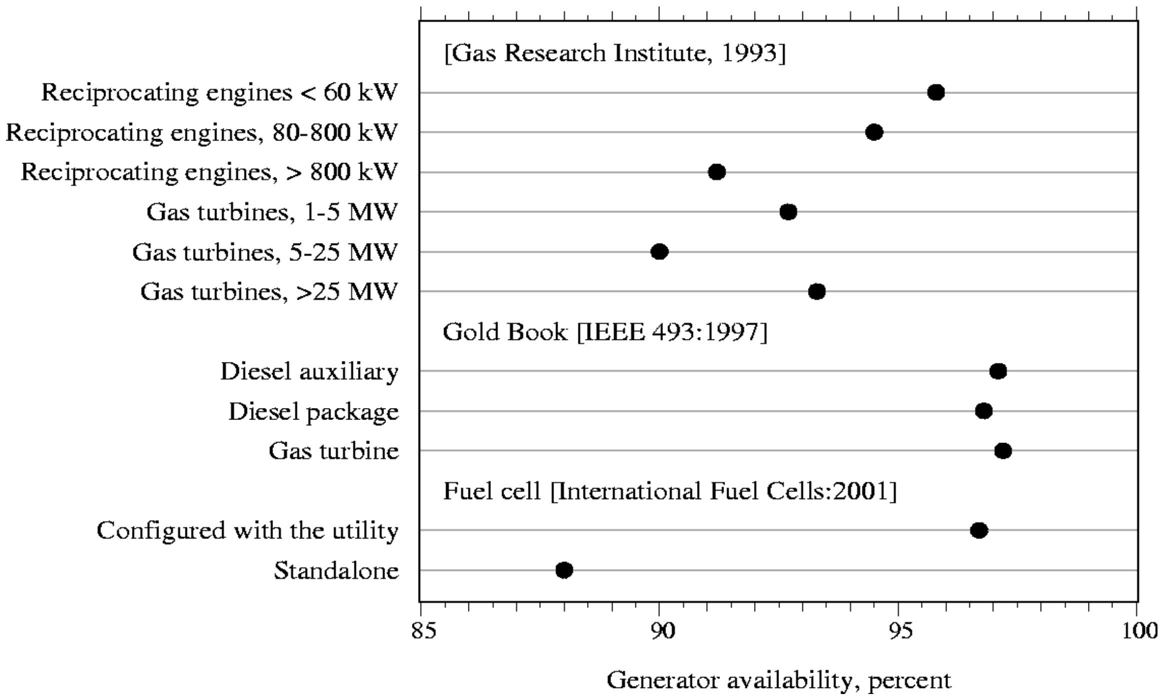


Figure 6-1
Availability of Generators Found in Various Studies [27,28,29]

For the case of three generators, where each generator has a 97% probably of operating, the probability of these generators being out of service is calculated in Table 6-3:

[27] Gas Research Institute (GRI) White Paper, "Reliability of Natural Gas Power Generation Systems," citing results from: Brown, H. W. and Stuber, F.S., *Reliability of Natural Gas Cogeneration Systems*, Final Report, GRI-93/0020, Sept. 1993.
[28] IEEE 493-1997 (Gold Book), *IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.*
[29] International Fuel Cells, Fuel Cell Reliability for the 12-Month Period Ending Nov. 1, 2001 as cited at http://www.ifc.com.

Table 6-3
Probability Calculation for Generator Being Out of Service

Units Out of Service	Probability	
0	0.97^3	= 0.912673
1 (r=2, n=3)	$3\,(0.97)^2\,(1\text{-}0.97)$	= 0.084681
2 (r=1, n=3)	$3\,(0.97)\,(1\text{-}0.97)^2$	= 0.002619
3	$(1\text{-}0.97)^3$	= 0.000027
	Sum	= 1.0

This table comes from the probability calculation where the number of generators running, given by *r*, out of a total number of generators, *n*, is found using the binomial distribution. This distribution yields the probability of exactly *r* successes in *n* trials with a probability of success *p*:[30]

$$P_r = {}_nC_r\, p^r (1-p)^{n-r} = \frac{n!}{r!(n-r)!} p^r (1-p)^{n-r} \qquad \textbf{Eq. 6-1}$$

It should be noted that these calculations are theoretical and don't include overlapping or common-mode failures. For generators, several factors contribute to common-mode failures:

Availability Terminology

availability

As applied either to the performance of individual components or to that of a system, it is the long-term average fraction of time that a component or system is in service and satisfactorily performing its intended function. An alternative and equivalent definition for availability is the steady-state probability that a component or system is in service, from IEEE Std 493, the *IEEE Gold Book*[31].

- Circuit availability
- Circuit Services Availability

[30] R. Billinton, *Power System Reliability Evaluation*, Gordon and Breach, Science Publishers, Inc., New York, 1970.

[31] IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems, ***IEEE Gold Book***, IEEE Standard 493, 1997.

distribution system availability

ASAI: The average service availability index represents the fraction of time (often in percentage) that a customer has received power during one year or the defined reporting period.

interruption

The loss of electric power supply to one or more loads, from IEEE Std 493, 1997.

interruption frequency

The expected (average) number of power interruptions to a load per unit time, usually expressed as interruptions per year, from IEEE Std 493, 1997.

unavailability

The long-term average time, as a fraction of total time, that a component or system is out of service due to failures or scheduled outages. An alternative definition is the steady-state probability that a component or system is out of service due to failures or scheduled outages. Mathematically, unavailability = 1–availability, from IEEE Std 493, 1997.

Availability Indices

Compared to other elements of SQRA, availability is perhaps the best defined. It has been applied most consistently at all levels of the power system and among different utilities throughout the world. Measurement parameters for availability have been established to be the operating, or up, time, (also 1- downtime), and stated as a percent of the total time of interest.

Transmission circuit services availability (Australia - SAIIR): The ability of a transmission entity's transmission network to provide transmission services to exit points to the level agreed in its connection agreements with distributors, transmission customers as:

$$1 - \frac{\sum \text{number of interrupted circuit hours}}{\text{Total number of circuits x 8760 hours}} \qquad \textbf{Eq. 6-2}$$

where

the *number of interrupted circuit hours* is defined in relation to each circuit in a transmission entity's transmission network, the number of hours during each reporting period in relation to which that circuit is unavailable to provide transmission services to exit points to the level agreed in connection agreements with distributors, transmission customers and generators *and that unavailability interrupts the provision of transmission services to exit points* required by distributors, transmission customers or generators at that time (excluding outages requested by a distributor, transmission customer or generator, but including all planned outages and unplanned outages in relation to the transmission entity's transmission network).

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