Electric Utility Distribution Network Enhancement Project

Volume 1
Final Report to
Visayan Electric Company (VECO)
PUBLIC VERSION

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December, 2002

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1
INTRODUCTION

EPRI was contracted by three utilities in the Republic of the Philippines to help optimize their strategic assets to improve power quality and reliability. The recently approved Philippine Distribution Code, and the move toward deregulation of electric utilities in the Philippines have increased their awareness of the need of improved reliability and power quality. EPRI put together a project team who customized the overall project methodology to meet each Client Utility's needs.

This report outlines the findings of the project team based on the questionnaires, site visit to the Philippines, orientation visit by representatives of the Philippine utilities to the U.S., vendor visits, product review, and data analysis. Many of the recommendations of this report are based on the practices of U.S. utilities with similar distribution systems and high levels of power quality and reliability.

This is the Public Version of Volume 1 of the Final Report of the Electric Utility Distribution Network Enhancement Project that excludes proprietary data. This volume focuses on Visayan Electric Company (VECO) and contains chapters that are specific to VECO. This volume also contains chapters that are common to all three Client Utilities: Cagayan Electric Power & Light Company (CEPALCO), Davao Light and Power Company (DLPC), and VECO.

The common chapters cover such topics as reliability indices, circuit coordination, reliability analysis software review, vegetation management, outage management, power quality, power quality monitoring, and cost of outage events. These chapters provide information on specific topics and outline areas of concern regarding reliability that are common to the Client Utilities. These chapters contain no proprietary data from the Client Utilities.

The VECO specific chapters may contain information common to all three utilities. Information that is proprietary to VECO, such as reliability data or financial information, has been removed from this version of Volume 1. These chapters cover such topics as a plan to meet the requirements of the Philippine Distribution Code, evaluation of current AM/FM/GIS system and recommendations on an outage management system, evaluation of the use of fiber optic communications, metering requirements for automated meter reading (AMR), roadmap for distribution automation, and financial analysis of the recommended improvements.

This report also contains several Appendices covering such topics as techniques for determining the cost of outages, equipment specifications, and vegetation management software. The equipment specified is all of US manufacture as required by the US Trade and Development Agency (TDA).

2
METHODOLOGY

The large scope of this project necessitated the use of many different methodologies to come to a set of recommendations. Data collection was performed using questionnaires and on-site visits to the client utilities. Distribution system product literature was researched to identify those products that would be most effective at achieving the goals of improved reliability and power quality (PQ). A group of representatives from the client utilities visited the United States so they could meet with U.S. vendors, utilities, and contractors.

Data Collection

Data Collection began with the delivery of questionnaires to the client utilities. The questionnaires covered such topics as reliability, engineering, maintenance, operations, accounting, finance, and safety. Once the responses were received, a site visit to the Philippines was planned. EPRI representatives visited the Philippine utilities from February 4, 2002, through February 22, 2002. These face-to-face meetings allowed a free and open exchange of data and ideas. Examples of the data collected are shown in the following list:

- Company profile
- Capital expenditure plan 2002
- Operating budget 2002
- Five-year plan
- Computer inventory
- GIS system description
- IT Infrastructure description
- Reliability indices
- Organization chart
- Outage history
- Outage data (examples)
- Circuit maps (examples)
- Construction Standards (examples)
- Relay settings (examples)
- Breaker data (examples)

- Station one-line diagrams (examples)
- Circuit model (example)
- System one-line diagram

Data collection has continued throughout the project. Using e-mail, EPRI representatives have been able to solicit the answers to questions as they have arisen.

Inception Report

In June of 2002, an Inception Report was delivered to the utilities for their review and approval. The Inception Report detailed the data collected, results of initial analysis, and proposed work plan. The report defined those areas on study that were considered important to the goals of the utilities and thus warranted further study. The three utilities agreed to the work plan and scope presented in the Inception Report. The Inception Report is included as Appendix J.

Vendor/Product Research

Data has been acquired from several U.S. vendors. This data has been used to establish recommendations for the equipment that will have the most impact on the reliability and PQ of the client utilities. Specifications for much of the equipment recommended in this report are located in Appendix F and vendor contact information is located in Appendix H. As part of the effort to evaluated possible products, two vendors were visited.

Vendor Site Visits

After the site visits were completed and the technologies identified that the three utilities were most likely to benefit from learning about, it became evident that there were two U.S. companies in particular that would be quality contributors to the feasibility study. These were GE Network Solutions in Englewood, Colorado, and Cooper Power in Milwaukee, Wisconsin. For this reason, although it was outside of the scope, the EPRI team visited these companies from May 28, 2002, to May 31, 2002. These visits were quite productive, both from the point of view of technology transfer, but also introducing the companies to potential markets in the Philippines.

Below are the file notes for the meetings with GE Network Solutions and Cooper Power Systems.

Visit with GE Smallworld

On May 29th, Charles Perry and Jim Reilly visited GE Network Solutions in Englewood, Colorado, to gather information on the Smallworld suite of products and determine their applicability to the needs of the three utilities. Smallworld is GE's product in the AM/FM/GIS arena. The scope of the meeting expanded from Smallworld, in particular, to include PowerOn, the broader integration platform with multiple applications. PowerOn provides outage

management and AM/FM/GIS functions, along with the ability to be integrated with SCADA, distribution automation, and customer information systems.

The meeting was held by Jim Green, Director of Industry Applications, Utility Solutions Division. During the presentation, considerable background material was transmitted that should be helpful to the client utilities.

- Introductions and expectations for the visit
- GE Network Solutions overview
- Core GIS overview and demonstration
- PowerOn overview and demonstration
- PowerOn applications, overview, and demonstrations
- PowerOn and supervisory control and data acquisition (SCADA)
- Questions, answers, and adjournment

The tools that were described in the meeting will form the core of major recommendations to the client utilities with respect to supporting infrastructure issues. Initially GIS and outage management are prime areas of major focus. Certain aspects of SCADA and data collection at substations were addressed secondarily.

The in-depth briefing by Jim Green and ensuing discussion provided an understanding of SmallWorld and insights into PowerOn. This suite of products fits the needs of the client utilities well. Consequently, the information received will form the basis of recommendations with respect to GIS and broader applications such as outage management.

We see some good opportunities for GE Network Solutions in the Philippines.

Visit with Cooper Power Systems

On May 29th and 30th, Cooper Power Systems was visited by Charles Perry and James Reilly. The depth of Cooper's product line in distribution system equipment is quite extensive. Most importantly, Cooper has products that fit the needs of the client utilities. Most important among these are reclosers, arresters, and pad transformers. The agenda for the visit included the following:

- Introduction to Cooper Power Systems – Products and International Marketing
- Technical Tour – Kyle Plant (Kyle distribution switchgear and capacitors))
- Project discussions

- Technical tour – Thomas A. Edison Technical Center
- Meeting with international management and staff
- Technical tour – Transformer products (arrestors and voltage regulators)

The visit concentrated on three areas:

- Products
- Migration from legacy system to one with state-of-the-art distribution technology
- Training

The introductory briefing by Bruce Meyer and Bo Southerlin set the stage for a very informative program.

At the Technical Center Antone Bonner explained well the ways in which we might structure pilot projects that can be a part of future projects. Some of the outcomes of the visit included:

- Charles expressed an interest in PV Series Analysis Software.
- Learned importance of four-wire U.S. system, ANSI vs IES standards.
- Learned about ENVIRONTEMP "green" fluid for transformers as opposed to oil.
- Learned about industrial, medium-voltage VFI+ relay line.
- Cooper Power granted access to their library to obtain background information helpful to analyzing the data collected from the client utilities. This will be most helpful in configuring any prospective solutions around U.S. products.
- We see some good opportunities for Cooper Power in the Philippines.

Although the visits to these vendors were not included in the scope of work for the assignment, it was included to further involve U.S. sourced vendors. Both companies appreciated the fact that export sales of their products were being kept in mind as a part of the TDA funded, feasibility study, and the proactive approach that EPRI-PEAC was taking.

United States Visit by Philippine Utilities

EPRI hosted a U.S. orientation tour for six engineers (two from each of the three client utilities) from February 24, 2002, to March 3, 2002.

The individuals participating, their respective utility, and title are shown in Table 2-1.

Table 2-1
Participating Utilities and Individual Participants to EPRI Orientation Tour

VECO	Oscar T. Rodriguez	Head, Power Marketing & Sales Department
	Nilo A. Felisilda	Head, Systems & Engineering Department
DLPC:	Raul C. Lucero	Asst. Vice President - Engineering Group
	Rodger S. Velasco	Senior Manager
CEPALCO	David Tauli	Head, Engineering Department
	Jose Abaya	Assistant to the Chairman

After the in-depth data gathering (interviews, site inspection of the facilities, and so on) of Phase I and the establishment of rapport with the staff at the utilities, gaining an understanding of their local situation, and the identification of areas for further attention, the EPRI team was in a position to recommend a specific itinerary that would best satisfy their needs.

One of the objectives of the U.S. trip was to establish contacts between the utilities and potential U.S. companies, and afford them exposure to U.S. solutions and practices. This is significant from the point of view of effectively transferring technology and expertise from the United States to the three client utilities. Because of scheduling reasons, this visit took place earlier in the work plan than originally planned. However, the timing of the visit afforded additional opportunities for technical exchanges. Timing the visit to coincide with DISTRIBUTECH, a major conference and exhibition for distribution utilities considerably enhanced the introduction of the visitors to potential providers of products, services, and systems in the United States.

DISTRIBUTECH

In support of the effort to involve U.S. companies, EPRI PEAC scheduled the visit of the six engineers and managers from the three utilities to the United States to coincide with DISTRIBUTECH. Because the three utilities are primarily distribution companies, DISTRIBUTECH provides an excellent venue for exposure to U.S. companies. Among the companies exhibiting at DISTIBUTECH are a number of companies that match needs of the three utilities as identified in the early stages of the EPRI PEAC study. Preliminary recommendations and specifications have been made around equipment manufactured by these companies. Introductions to these companies has considerably facilitated the exchange of technical information during the study and will lead to business opportunities when recommendations are implemented.

DISTRIBUTECH is a leading international conference on information technology and distribution automation utility and energy trends and ideas for the industry's leading experts.

This year, it was attended by approximately 4000 utility professionals from electric and gas utilities, pipelines companies, energy service companies, manufacturers, and consulting engineers.

More than 260 companies exhibited. The companies represented 52 product groups and 22 services

The companies that interested the three utilities are shown in the Table 2-2. These companies were contacted as part of this study or asked to exchange technical or commercial information.

Table 2-2
Vendors Present at Distributech That Met With Representatives of the Philippine Utilities

ABB Inc.	Advantica Stoner
AES Intricity	AMS
ATL Corporation	Badger Meter, Inc.
Caprock Mfg. Inc.	CES International
Comverge Technologies, Inc.	Cooper Power Systems
Cutler-Hammer	Cybectec, Inc.
DAQ Electronics, Inc.	Distribution Control Systems, Inc.
Draper Inc.	DTN Weather Services (Meteorlogix)
E.O. Schweitzer Manufacturing Co., Inc	Eaton Cutler-Hammer
Enerwise Global Technologies, Inc.	ESRI
Exeltech	GE Power Systems
Gentec, Inc.	Hunt Technologies, Inc.
Imedeon	Intergraph Utilities & Communications
Internet-Metering.net	Invensys-Imserv
Itron	MAPFRAME Corporation
MDSI Mobile Data Solutions	Microwave Data Systems Inc.
Motorola	Pulsar Technologies, Inc.
S&C Electric Company	Schneider Electric
Schweitzer Engineering Laboratories, Inc.	SCT Global Energy
SensorLink Corporation	Serveron Corp.

Siemens Power T & D	Smart Systems Technologies
Stoner Associates	Subnet Solutions, Inc.
Telemetrix Technologies, Inc.	TWACS by DCSI

Visits to U.S. Utilities

In addition to examining PQ issues, the visits were organized to allow for maximum exposure to the internal systems of the host utilities in the United States.

Visits to two utility locations were arranged:

- A visit to Florida Power & Light (a vertically integrated, investor owned utility) with PQ and reliability systems that incorporates the high standards and practices that the three client utilities wished to examine first hand.
- A visit to the Florida Keys Electric Cooperative that is approximately the same size as the three client utilities and is located in a similar climate with similar managerial issues.

The overall purpose of the visit was to see first hand how a utility of similar size in the United States organizes itself to meet reliability challenges and incorporate PQ in its operations. Secondarily, as intended, the visitors were introduced to vendors of products and services that are available in the U.S. market from U.S. sources that can be effectively transferred to the client utility-owned operations and lead to an improvement in distribution network reliability.

EPRI PEAC

The utility representatives visited EPRI PEAC offices and facilities in Knoxville, Tennessee, with a complete tour of the laboratory and briefings on PQ and reliability activity. They were also given a presentation on the history and capabilities of EPRI PEAC.

Reliability Assessment Spreadsheet

The project team developed a spreadsheet model of distribution feeder reliability. The Microsoft Excel spreadsheet Philippines_reliability.xls implements the model. The user inputs basic parameters of the circuit, and the spreadsheet estimates SAIFI, SAIDI, and MAIFI.

The spreadsheet models a simple but common configuration: the circuit has one "main line". Off of the main line, a number of taps can be used, either with fuses or reclosers. The main line may have evenly spaced reclosers or evenly spaced switches or both.

The spreadsheet allows very quick examination of the tradeoffs between different design, protection, and operations practices. It does not replace a full-blown reliability-modeling package, but the spreadsheet requires just a small amount of data entry (dedicated programs often require a lot of data entry).

3
RELIABILITY INDICES

The Philippine Distribution Code specifies which reliability indices must be used by Distributors. Section 3.3.2 of the Code requires all Distributors to use System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Momentary Average Interruption Frequency Index (MAIFI). This is a departure from the indices historically used by utilities in the Philippines. Previous to the adoption of the Philippine Distribution Code, most utilities used Cumulative Interruption Time (CIT) and Interruption Frequency Rate (IFR). The main difference between the calculation of the previously used indices, CIT and IFR, and the indices currently required by the Code is the need to have an accurate customer count per protective device.

Data Collection

There are three main pieces of information that must be collected for each interruption in order to calculate the required reliability indices: the time the interruption began, number of customers affected, and the time the interruption ended. Additional data that can provide valuable information regarding the interruption include: interrupting device and interruption cause. Of these 5 variables, four are routinely captured by the three utilities: the time the interruption began, the time the interruption ended, interrupting device, and cause code. This leaves the collection of the number of customers affected by the interruption.

Perhaps the best system for keeping track of the number of customers is an AM/FM/GIS (Automated Mapping/Facilities Management/Geographic Information System) system. Once such a system is put in place, the customer count per interrupting device is easily obtained through reporting techniques. Of course, such a system cannot be static. It must be constantly maintained in order to provide accurate data. Procedures must be put in place that require any changes in the field be reported to a central location for inclusion in the AM/FM/GIS system.

Another computerized method of tracking the number of customers is to associate each customer (usually a revenue meter) with a supply transformer. This is often done in AM/FM/GIS systems also, but can be done in a customer accounting database if such a system is not available. Once this data exists, a customer count per device can be maintained by identifying every transformer downstream of the protective device and than totaling the number of customers. This can be quite time consuming but does work. The customer count data would need to be updated periodically as the distribution system changes and new customers are added.

The most rudimentary method is to physically count the number of customers in each protection zone and maintain a manual list. This method was used for many years by North American

utilities until computerized systems became more popular. In such a system, the customer count must be updated periodically to reflect changes in the distribution system.

An outage management system can aid in the collection of the interruption data required for the calculation of indices. Chapter 7 covers the features of an outage management system.

Calculation of Indices

Once the appropriate data has been collected, it must be manipulated to calculate the reliability indices. For example, interruption data must be separated into sustained interruptions and momentary interruptions. Also, some interruptions are excluded under specific circumstances detailed in the Philippine Distribution Code.

Excluded Events

Section 3.3.3 of the Philippine Distribution Code specifies which interruptions must be included in the calculation of reliability indices, as well as those that can be excluded. Article 3.3.3.2 specifies the excluded events. These include:

- Outages that occur on the secondary lines of the Distribution System
- Outage due to generation, transmission line, or transmission substation failure
- Planned Outages where the Customers or Users have been notified at least three (3) days prior to the loss of power
- Outages that are initiated by the System Operator/Market Operator during the occurrence of Significant Incidents or the failure of their facilities
- Outages caused by Adverse Weather or Major Storm Disasters which result in the declaration by the government of a state of calamity in the franchise area of the Distributor
- Outages due to other events that the Energy Regulatory Commission (ERC) shall approve after due notice and hearing

In addition to the above exclusions, there are some cases where momentary interruptions should be excluded from the calculation of MAIFI. Guidance on the calculation of reliability indices is given in the Philippine Distribution Code and IEEE 1366[[1]]. While not covered in the Code, IEEE 1366 covers the exclusion of momentary interruptions associated with a device lockout. For example, if a recloser operates four times for the same fault and locks out, the 3 momentary interruptions caused by this sequence are not counted. Similarly, if the device operated 3 times for a fault and on the 3rd reclose it holds, the three operations are considered a single momentary interruption. IEEE 1366 specifies a 5 minute window in which these operations can occur. The Philippine Distribution Code does not place a time limit on momentary interruptions, instead specifying that the "duration is limited to the period required to restore service by automatic or supervisory controlled switching operations or by manual switching at a location where an

[1] IEEE Std. 1366-1998, "Trial Use Guide for Electric Power Distribution Reliability Indices."

operator is immediately available." The IEEE standard uses a definite time, 5 minutes, to define a momentary interruption to make automation of these calculations easier.

A more complicated example of the exclusion of momentary interruptions is a permanent fault downstream of two reclosers. Figure 3-1 shows a distribution feeder with two reclosers in series and a permanent fault near the end of the feeder. If the resulting fault current is high enough for recloser R1 to respond to the fault, then recloser R2 will operate on its fast curve (usually two operations), then recloser R1 will operate on its fast curve (usually two operations), then R2 will operate on its slow curve (usually two operations) and then lock out. Customers in Zone 2 will have seen a total of 4 operations of recloser R2 and 2 operations of recloser R1. Because the fault is permanent and recloser R2 locked out, none of the customers in Zone 2 will be considered as experiencing momentary interruptions. Instead, they will count as having a sustained interruption. Customers in Zone 1 will have seen two operations of recloser R1. After the second operation, their service will have restored to normal operation. Because the two interruptions are related to the same fault, only one momentary interruption will be counted.

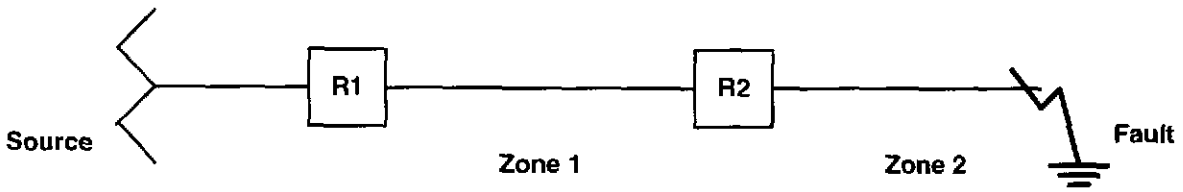


Figure 3-1
Example of a Faulted Circuit

As you can see, the exclusion of momentary interruptions can become quite involved. While the IEEE standard gives some guidance on this subject, the Philippine Distribution Code does not. At this point, each Distributor will have to document the method used for calculation of MAIFI and prepare to defend that calculation with the ERC. At some point, the ERC is likely to provide guidance for the calculation of MAIFI so that the calculation is consistent among the distributors.

Calculation of Indices

The definitions of the reliability indices are included in the Philippine Distribution Code in Section 3.3.2. SAIFI is defined as follows:

> The System Average Interruption Frequency Index shall be defined as the total number of sustained Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

As an equation it would be as shown in Equation 3-1:

$$SAIFI = \frac{\sum N_i}{N_T}$$ **Equation 3-1**

SAIDI is defined as:

> The System Average Interruption Duration Index shall be defined as the total duration of sustained Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

As an equation it would be as shown in Equation 3-2:

$$SAIDI = \frac{\sum r_i N_i}{N_T}$$ **Equation 3-2**

MAIFI is defined as:

> The Momentary Average Interruption Frequency Index shall be defined as the total number of momentary Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

As an equation is would be as shown in Equation 3-3:

$$MAIFI = \frac{\sum ID_i N_i}{N_T}$$ **Equation 3-3**

where

i = interruption event,
r_i = restoration time for each interruption event,
T = total,
ID_i = number of interrupting device operations,
N_i = number of interrupted customers for each interruption event,
N_T = total number of customers served

We have already discussed the problems associated with counting the number of momentary interruptions. Another difficult number to define is the total number of customers served. The exact definition of this term is still being debated in the IEEE. There are three possible approaches for determining the "number of customers within the same period." First you can use the number of customers served at the end of the period. This seems like a logical approach. However, if the number of customers was increasing during the period, the reliability indices will be reduced because the denominator is larger. The second approach is to use the number of customers at the beginning of the period. This can cause an increase in the reliability indices if the number of customers increased during the period. A third approach is to use the average of the number of customers at the beginning of the period and the number of customers at the end of the period. In this way, any changes in the number of customers during the period are accounted for.

4
CIRCUIT COORDINATION

Types of Distribution System Faults

Faults are the root cause of sags and interruptions. Obviously, if faults are reduced, the incidence of sags and interruptions will be reduced. Incidence levels can be reduced in several ways including:

- Trimming trees
- Using animal guards
- Using arresters
- Using tree wire (covered wire)
- Using aerial or underground cable
- Identifying and replacing poorly performing hardware
- Performing line patrols including thermal scanning

Faults may be either *temporary* or *permanent*. A permanent fault is one where permanent damage is done to the system. Permanent faults include insulator failures, broken wires, or failed equipment (such as transformers and capacitors). Virtually all faults on underground equipment are permanent. Most equipment fails to a short circuit. Permanent faults on distribution circuits usually will cause sustained interruptions for some customers. To clear the fault, a fuse, sectionalizer, recloser, or breaker will have to operate to interrupt the circuit. The most critical location is the three-phase mains, because a fault on the main feeder will cause an interruption to all customers on the circuit. Permanent faults also may cause momentary interruptions for a customer. A common example is a fault on a fused lateral (tap). Often, a practice called *fuse saving* is used where an upstream breaker or recloser attempts to open before the fuse blows. After the first attempt to save the fuse, if the fault is still there, the breaker allows the fuse to clear the fault. If a fault is permanent, all customers on the circuit will experience a momentary, and the customers on the fused lateral will experience a sustained interruption.

If a circuit is interrupted and then reclosed after a delay, a temporary fault does not involve permanent damage to the system and the system will then operate normally. Temporary faults make up 60% to 90% of faults on overhead distribution systems. The causes include lightning strikes, conductors slapping together in the wind, tree branches that fall across conductors and then fall off, animals that cause faults and then fall off, and insulator flashovers caused by pollution. Temporary faults are the main reason that reclosing is used almost universally on distribution breakers and reclosers (on overhead circuits) around the world. Temporary faults

will cause sustained interruptions if the fault is downstream of a fuse and fuse saving is not used successfully. For faults on the feeder backbone, all customers on the circuit will have a momentary interruption.

One way to improve the fault-rate performance is to track the location and type of faults. It is relatively straightforward to track permanent faults. The effort in tracking faults is paid back by targeting maintenance efforts to the most important sections. These are not necessarily the locations with the most faults per mile. The number of customers on a circuit and the type of customers on a circuit are important considerations. For example, a suburban circuit with many high-technology, commercial customers should warrant different treatment than a rural circuit with fewer, mostly residential and agricultural, customers. How this is weighted depends on the utilities' philosophy.

The Effect of Feeder Reclosing on Reliability

Maximum reliability is achieved for a distribution circuit when the circuit is designed and operated in such a way as to minimize the effects of a fault. Keeping in mind that as many as 90% of faults on overhead distribution systems are temporary, the following guidelines are often employed to minimize the effects of faults:

- All faults are given the opportunity of being temporary. This is accomplished by providing a reclosing function on system-protection devices.
- Permanent faults must interrupt the smallest portion of the circuit that is necessary to isolate the faulted section.

Reclosing provides a way of allowing temporary faults to remove themselves from the system by providing a short period in which the circuit, or section, is de-energized. During this period, the fault arc is allowed to extinguish. Faults caused by such things as vegetation contact, animal contact, or contaminated insulators will often be cleared by this de-energized period. Thus, when the protective device recloses, the circuit will again be healthy. Various sources place the success rate of reclosing at 60% to 90%. Thus, in the worst case, it could eliminate up to 90% of all permanent outages experienced on a circuit with no reclosing.

Figure 4-1 shows an example distribution circuit used to illustrate the benefits of reclosing. The feeder has approximately 1500 customers and 6 MVA of load. This feeder was not created to represent a specific feeder. Instead, it was created to show the relative change in performance when various coordination schemes are used.

A model of the circuit in Figure 4-1 was developed using SynerGEE Electric software and a computerized reliability analysis performed. For the analysis, outage rates were selected such that approximately 80% of all faults are temporary.

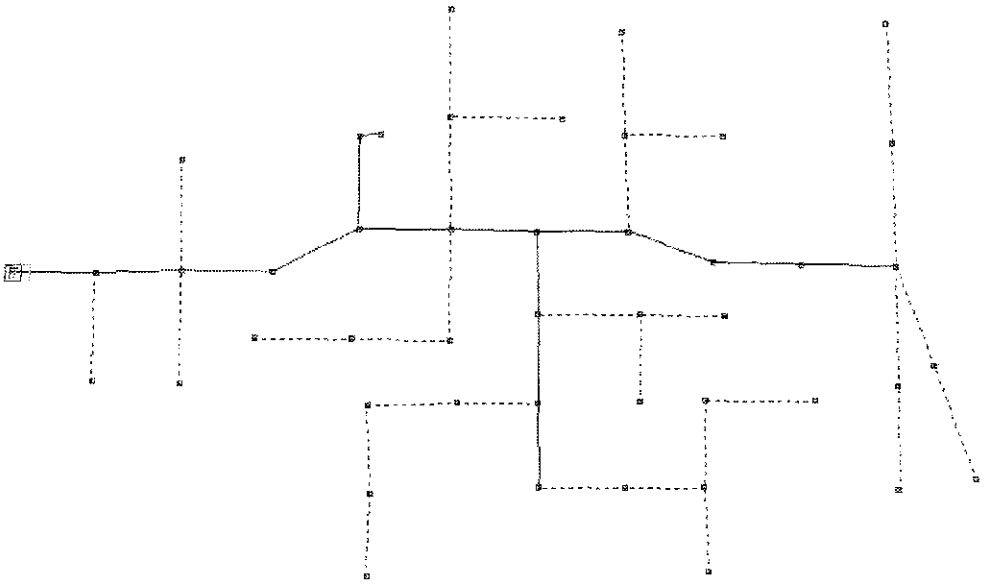


Figure 4-1
Example Distribution Feeder Without Feeder Reclosing

Table 4-1 presents the results of the reliability analysis on the feeder without feeder reclosing. As you can see, SAIDI (System Average Interruption Duration Index) is quite high at approximately 26 hours. SAIFI (System Average Interruption Frequency Index) is also high at 6.6 interruptions per year. Note that MAIFI (Momentary Average Interruption Frequency Index) is zero. Without reclosing, all faults are permanent, so no outages are considered to be momentary.

Table 4-1
Reliability Results for Feeder Without Feeder Reclosing

Feeder	SAIFI				SAIDI				MAIFI			
Name	Tot	A	B	C	Tot	A	B	C	Tot	A	B	C
Total System	6.547	6.547	6.547	6.547	26.188	26.188	26.188	26.188	0.000	0.000	0.000	0.000
Feeder Node_842790000	6.547	6.547	6.547	6.547	26.188	26.188	26.188	26.188	0.000	0.000	0.000	0.000

Next, feeder reclosing was enabled in the model. The protecting device was modeled as being a breaker with three-phase interrupting. In this mode, temporary faults are cleared by the reclosing operation, avoiding permanent outages. As you can see in Table 4-2, the SAIDI for the feeder was dramatically reduced to 4.4 hours per year. Also, the SAIFI dropped to just more than 1 interruption per year. The compromise comes in the form of an increase in the MAIFI to 5.5 momentary interruptions per year. For most customers, this tradeoff is easily accepted as

most would prefer to trade just more than 20 hours of interruption for a few momentary interruptions. Keep in mind that this model is somewhat simplistic in that it does not contain fuses on any laterals. Later in this section, this feeder with what would be considered as normal circuit coordination for North America will be analyzed.

Table 4-2
Reliability Results for Feeder With Feeder Reclosing

Feeder	SAIFI				SAIDI				MAIFI			
Name	Tot	A	B	C	Tot	A	B	C	Tot	A	B	C
Total System	1.085	1.085	1.085	1.085	4.400	4.400	4.400	4.400	5.502	5.502	5.502	5.502
Feeder Node_842790000	1.085	1.085	1.085	1.085	4.400	4.400	4.400	4.400	5.502	5.502	5.502	5.502

The next scenario included the addition of a three-phase hydraulic recloser to the midpoint of the feeder (see Figure 4-2). Midpoint reclosers are most commonly used on suburban and rural circuits where the main line of the feeder can be quite long. On short, high-density, urban circuits, reclosers may be used on laterals, but are seldom used on the main line. On long circuits, more than one recloser may be required along the main line of a circuit because of the reduction in fault current as one moves farther from the station. In the case of a long circuit, the location of reclosers will often be determined by the distance from the recloser at which it can detect a fault. At the point where the fault current falls below the level that can be safely detected by the recloser, another recloser with lower trip settings is installed.

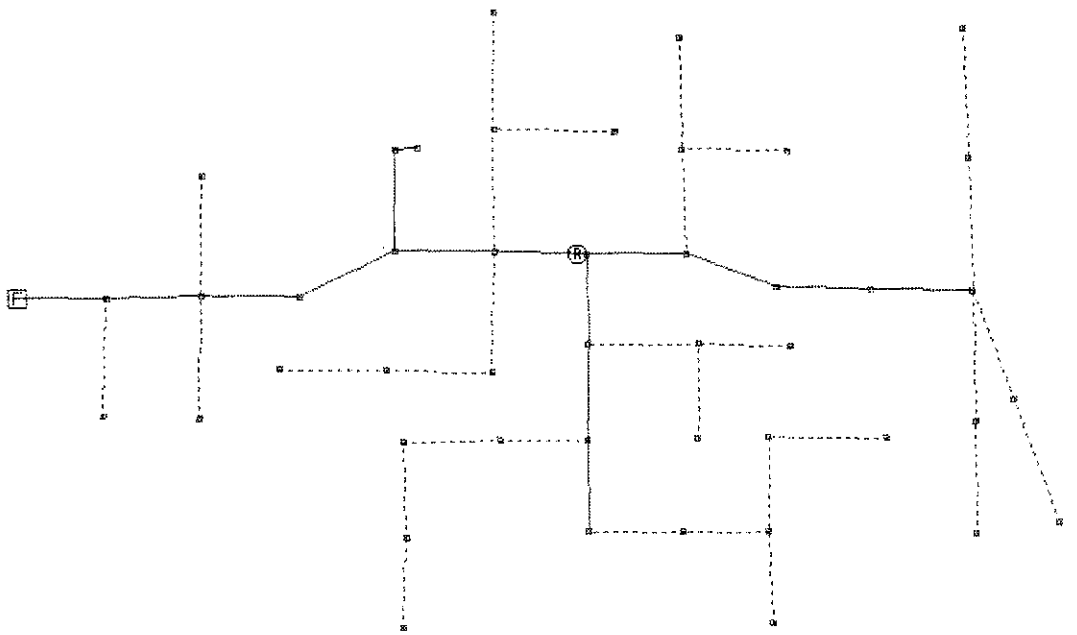


Figure 4-2
Feeder With Recloser at Midpoint (Legend: Recloser = ®)

The results of adding the midpoint recloser are shown in Table 4-3. As you can see, the SAIFI, SAIDI, and MAIFI have all been reduced. This is to be expected because permanent, as well as temporary, faults downstream of the midpoint recloser will affect fewer customers.

Table 4-3
Reliability Results for a Feeder With Feeder Reclosing and a Midpoint Recloser

Feeder	SAIFI				SAIDI				MAIFI			
Name	Tot	A	B	C	Tot	A	B	C	Tot	A	B	C
Total System	0.837	0.810	0.797	0.901	3.470	3.362	3.309	3.722	4.049	3.906	3.837	4.381
Feeder Node_842790000	0.837	0.810	0.797	0.901	3.470	3.362	3.309	3.722	4.049	3.906	3.837	4.381

In the final scenario, all single-phase laterals have been fused with fuses selected to provide fuse-saving as described later in this chapter. This circuit is shown in Figure 4-3.

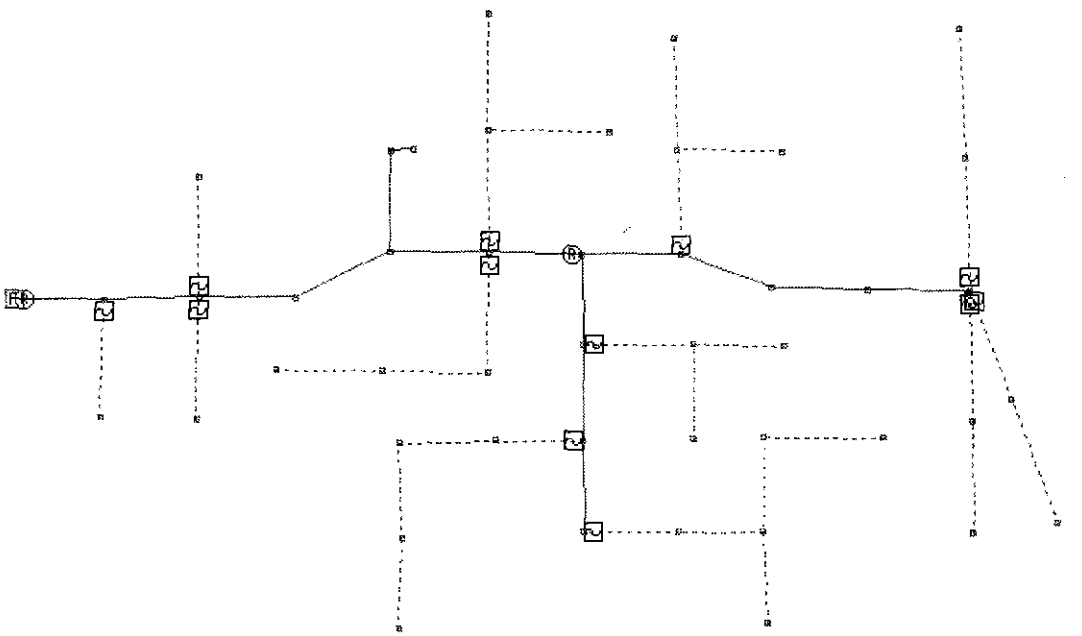


Figure 4-3
Feeder With Feeder Reclosing, Midpoint Recloser, and Fused Laterals

Fusing the laterals further reduces the amount of the feeder that is interrupted for permanent faults. Any temporary fault on a lateral will be cleared by the recloser or feeder breaker, while permanent faults will be cleared by the fuses. The results are shown in Table 4-4. As you can see, the SAIFI, SAIDI, and MAIFI are all improved.

Table 4-4
Reliability Results for Feeder With Feeder Reclosing, Midpoint Recloser, and Fused Laterals

Feeder	SAIFI				SAIDI				MAIFI			
Name	Tot	A	B	C	Tot	A	B	C	Tot	A	B	C
Total System	0.608	0.592	0.581	0.649	3.096	3.015	2.962	3.299	2.363	2.323	2.274	2.484
Feeder Node_842790000	0.608	0.592	0.581	0.649	3.096	3.015	2.962	3.299	2.363	2.323	2.274	2.484

These reliability improvements are the result of circuit coordination techniques alone. Improvements in such areas as right-of-way maintenance, crew response time, or repair time have not been considered. As you can see, the method of protection selected for a feeder can have a dramatic effect on its reliability.

Figure 4-4 shows the coordination for the devices in the example feeder. The recloser acting as the feeder breaker (device 1) and the midpoint recloser (device 2) are both set to operate twice on a fast curve and twice on a delayed curve before locking out. The fuses in the section of the feeder protected by the feeder breaker (device 3) are selected such that they coordinate properly with the feeder breaker (device 1). Likewise, the fuses in the section of the circuit protected by the midpoint recloser (device 4) are selected to coordinate with the midpoint recloser (device 2). This type of coordination is known as fuse saving and is explained in more detail later in this chapter.

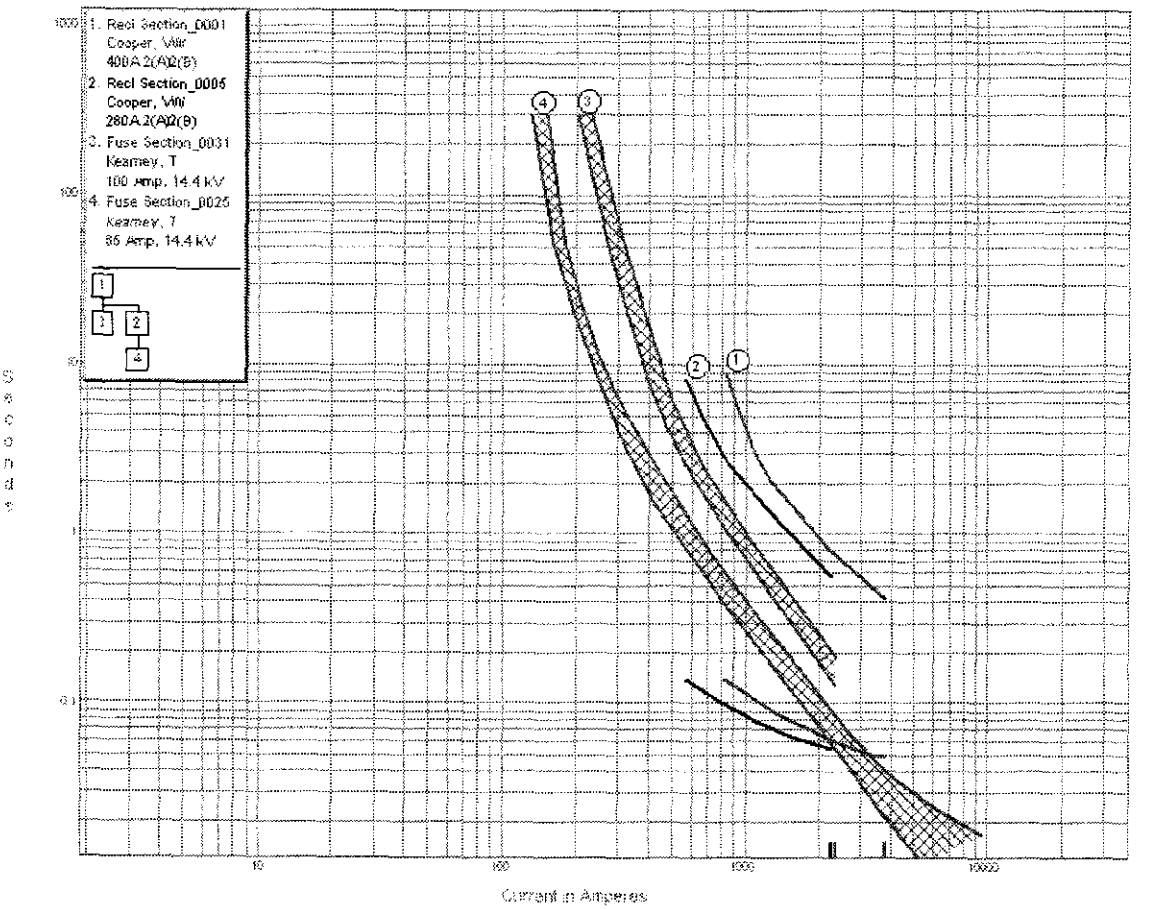


Figure 4-4
Device Coordination for Example Feeder

Fuse-Saving and Fuse-Blowing Coordination Schemes

Fuse-saving is a protection scheme where a breaker or recloser is used to operate before a lateral fuse. This protection scheme is used because a fuse does not have reclosing capability, but the breaker (or recloser) does. Fuse-saving is usually implemented with an instantaneous relay element (or the fast curve on a recloser). The instantaneous element is disabled after the first fault, so after the breaker recloses, if the fault is still there, the system is coordinated so the fuse blows. Because most faults are temporary, fuse-saving will prevent a number of lateral fuse operations.

The main disadvantage of fuse-saving is that all customers on the circuit see a momentary interruption for lateral faults. Because of this, many utilities are switching to a fuse-blowing scheme. The instantaneous relay element is disabled, and the fuse is always allowed to blow.

Fuse-saving is primarily directed at reducing the sustained interruptions; fuse-blowing is primarily aimed at reducing the number of momentary interruptions. To further discover the differences in these two techniques, first, refer to the example circuit in Figure 4-5.

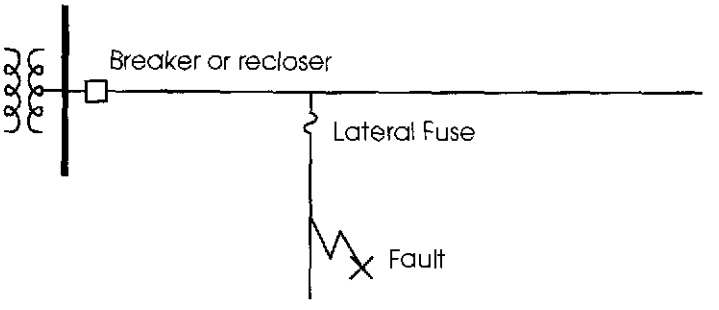


Figure 4-5
Sample Circuit for Use in Comparing Fuse-Saving and Fuse-Blowing During a Fault on a Lateral

Now, refer to Table 4-5 for a comparison of the sequence of events for each mode of operation (that is, fuse-saving and fuse-blowing).

Table 4-5
A Comparison of the Sequence of Events for Fuse-Saving and Fuse-Blowing

Sequence of Events for Fuse-Saving	Sequence of Events for Fuse-Blowing
For a Temporary Fault	
1. The breaker operates on the instantaneous curve before the fuse operates. 2. The breaker recloses. 3. The fault is gone, so no other action is necessary.	1. The fuse operates. 2. Crews must be sent out to replace the fuse.

necessary.	
For a Permanent Fault	
1. The breaker operates on instantaneous curve before the fuse operates. 2. The breaker recloses. 3. The fault is still there. 4. The instantaneous operation is disabled, so the fuse operates. 5. Crews must be sent out to fix the fault and replace the fuse.	1. The fuse operates. 2. Crews must be sent out to fix the fault and replace the fuse.

Industry Usage

Until the late 1980s, fuse-saving was almost universally used in the U.S. As power quality (PQ) concerns grew, some utilities switched to a fuse-blowing protection scheme. A survey that is done periodically by the Institute of Electrical and Electronics Engineers (IEEE) on distribution protection practices has shown a decrease in the use of fuse-saving as shown in Table 4-6.

Table 4-6
Results of Surveys by the Institute of Electrical and Electronics Engineers on the Percentage of Utilities That Use Fuse-Saving[2]

Survey Year	Percent of Utilities
1988	91
1994	71

Another survey performed in 1996 showed a mixture of practices at utilities (see Table 4-7). A few utilities used fuse-blowing because they indicated that fuse-saving was not successful. Many of the "mixed practices" utilities decided their choice of fuse-saving or fuse-blowing for a specific application on a case-by-case basis. Many of these normally used fuse-saving but switched to fuse-blowing if too many PQ complaints were received.

Table 4-7
1996 PTI Survey on Line Protection Methods[3]

[2] Working Group on Distribution Protection, W. M. Strang, Chair, "Distribution Line Protection Practices Industry Survey Results IEEE Power System Relaying Committee Report," *IEEE Transactions on Power Delivery*, vol. 10, no. 1, pp. 176-186, Jan. 1995.
[3] T. A. Short, "Fuse Saving and Its Effect on Power Quality." presented at the EEI Distribution Committee, Phoenix, AZ, March 28-31, 1999.

Line Protection Method	Percent of Utilities
Fuse-saving	40
Mixture of fuse-saving and fuse-blowing	33
Fuse-blowing	27

Effects on Momentaries and Sustained Interruptions

The change in the number of momentaries (as a result of switching from fuse-saving to fuse-blowing) can be estimated most simply by using the ratio of the length of the mains to the total length of the circuit including all laterals.

For example, if a circuit has 5 miles of mains and 10 miles of laterals off of that, the number of momentaries after switching to fuse-blowing would be 1/3 of the number of momentaries with fuse-saving (5/(5+10) = 2/3). This calculation assumes that the mains and laterals have the same fault rate. If the fault rate on laterals is higher (which it often is because of less tree trimming and other factors), the number of momentaries would be even less. From this calculation, it is easy to see how dramatically using fuse-blowing can reduce momentaries. No other methods exist that can so easily eliminate 30% to70% of momentaries.

The effect on reliability of going to a fuse-blowing scheme is a bit more difficult to estimate. Fuse-blowing will increase the number of fuse operations by 40% to 500% [3,[4],[5]]. This increase in fuse operations will increase the average frequency of sustained interruptions by 10% to 60%. Note that many variables can change the ratios. One example is given in Figure 4-6.

[4] R. C. Dugan, L. A. Ray, D. D. Sabin, G. Baker, C. Gilker, and A. Sundaram, "Impact of Fast Tripping of Utility Breakers on Industrial Load Interruptions," *IEEE Industry Applications Magazine*, vol. 2, no. 3, pp. 55-64, May-June, 1996.

[5] T. A. Short and R. A. Ammon, "Instantaneous Trip Relay: Examining Its Role," *Transmission & Distribution World*, vol. 49, no. 2, Feb. 1997.

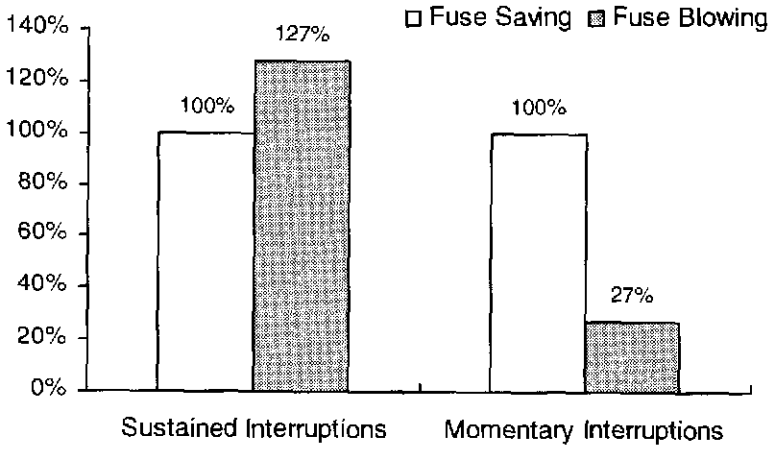


Figure 4-6
Comparison of Fuse-Saving and Fuse-Blowing on Hypothetical Circuit with Mains: 10 Miles, Fault Rate=0.5/Mile, 75% Temporary and Laterals: 10 Miles Total, 20 Laterals, Fault Rate=2/Mile, 75% Temporary

Note that the effect on sustained interruptions is not equally applied. Customers on the mains will see no difference in the number of permanent interruptions. Customers on long laterals may have many more sustained interruptions with a fuse-blowing scheme.

Coordination Limits of Fuse-Saving

One of the main reasons that utilities have decided not to use fuse-saving is that it is difficult to make it work. Fuses are fast relative to breakers, so where fault currents are high, the fuse can blow before the breaker trips. However, the breaker will likely have received a trip signal from the relay and will open even if the fuse blows. This will result in a fuse operation and a momentary for all customers on the circuit. The most common lateral fuses used are K links, which are relatively fast fuses. Most distribution circuit breakers are 5-cycle breakers. For fuse-saving to work, the breaker must open before the fuse blows, so the fuse needs to survive for the time it takes the instantaneous relay to operate (approximately 1 cycle maximum) plus the 5 cycles for the breaker. As an illustration, Figure 4-7 shows the limit of coordination of a five-cycle breaker and a 100-K fuse. Fuse-saving will only coordinate for fault levels less than 1360 A. Smaller fuses will be worse. Note that the breaker time is coordinated with a damage curve of the fuse. The damage curve is 75% of the operating time of the minimum melt curve. Not all protection engineers coordinate using the damage curve, but it provides some conservatism.

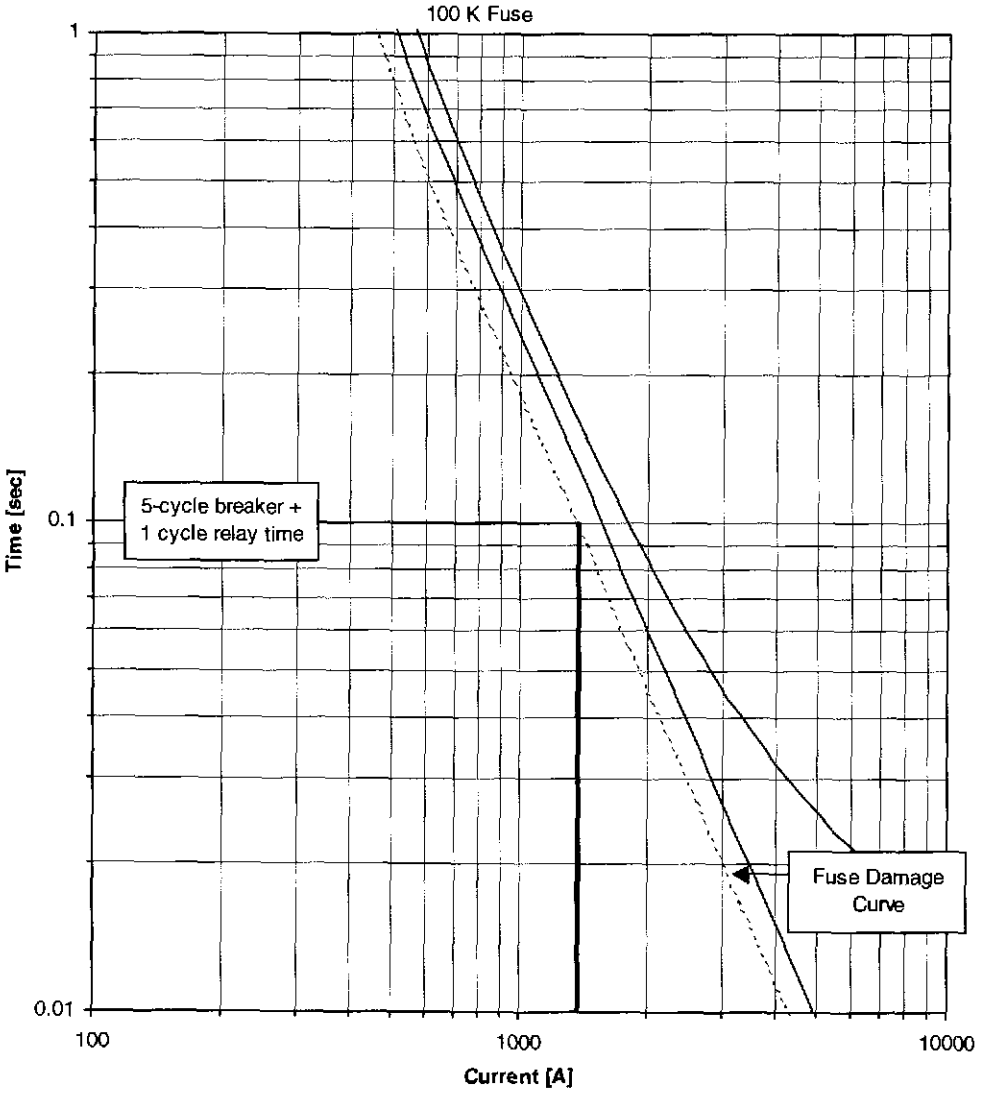


Figure 4-7
Coordination of a 100-K Lateral Fuse With a Five-Cycle Breaker

Table 4-8 and Table 4-9 show the limits of coordination of several common lateral fuses for a standard breaker (five cycle) and a fast breaker/relay combination (three-cycle breaker and ½-cycle relay).

Table 4-8
Maximum Fault Currents for Fuse-Saving Coordination for Several Common Fuse Links for a Five-Cycle Breaker and a One-Cycle Relay Time

K links		T links	
Size	Critical Current (Amps)	Size	Critical Current (Amps)
20K	254	20T	433
25K	323	25T	552
30K	398	30T	699
40K	520	40T	896
50K	665	50T	1125
65K	816	65T	1428
80K	1078	80T	1790
100K	1354	100T	2277
140K	2162	140T	3447
200K	3401	200T	5436

Table 4-9
Maximum Fault Currents for Fuse-Saving Coordination for Several Common Fuse Links for a Three-Cycle Breaker and a ½-Cycle Relay Time

K links		T links	
Size	Critical Current (Amps)	Size	Critical Current (Amps)
20K	332	20T	565
25K	424	25T	723
30K	522	30T	920
40K	682	40T	1175
50K	875	50T	1479
65K	1070	65T	1878
80K	1407	80T	2346

100K	1763	100T	2975
140K	2823	140T	4522
200K	4409	200T	7122

Table 4-10 and Table 4-11 translate these fault currents into distances from the substation at 12.47 kV (assuming an 8-kA fault level at the substation). Note that only the larger fuses shown (>100 A) will coordinate for significant portions of the feeder. Smaller fuses used as second- and third-level fuses would not coordinate over the length of most feeders. The situation is even worse at higher voltages. At 24.94 kV, the distances in Table 4-10 and Table 4-11 are doubled, so fuse-saving is more difficult to achieve for longer distances at higher voltages.

Table 4-10
Minimum Distance From the Substation Where the Given Fuse Coordinates for Fuse-Saving for a Five-Cycle Breaker and a One-Cycle Relay Time (12.47 kV, 500 kcmil Phase, 4/0 Neutral), (For 24.94 kV, Multiply Distances by 2)

K links		T links	
Size	Critical Distance (Miles)	Size	Critical Distance (Miles)
20K	26.5	20T	15.5
25K	20.8	25T	12.2
30K	16.9	30T	9.6
40K	12.9	40T	7.5
50K	10.1	50T	6.0
65K	8.3	65T	4.8
80K	6.3	80T	3.8
100K	5.0	100T	3.1
140K	3.2	140T	2.1
200K	2.1	200T	1.5

Table 4-11
Minimum Distance from the Substation Where the Given Fuse Coordinates for Fuse-Saving for a 3-Cycle Breaker and a ½-Cycle Relay Time. (12.47 kV, 500 kcmil Phase, 4/0 Neutral) (For 24.94 kV, Multiply Distances by 2.)

K links		T links	
Size	Critical Distance (Miles)	Size	Critical Distance (Miles)
20K	20.3	20T	11.9
25K	15.9	25T	9.3
30K	12.9	30T	7.4
40K	9.9	40T	5.8
50K	7.7	50T	4.6
65K	6.3	65T	3.7
80K	4.8	80T	3.0
100K	3.9	100T	2.4
140K	2.5	140T	1.7
200K	1.7	200T	1.3

If smaller K links—such as 100-K and 65-K fuses (the most common lateral fuses used)—are used, then fuse-saving isn't going to work very well. A strong argument exists for going to a fuse-blowing scheme. No sense can be found in having a momentary every time a fuse blows (which is what happens when the breaker is not fast enough to save the fuse).

Long-Duration Faults and Wire Burndowns with Fuse-Blowing

A drawback of fuse-blowing is that for faults on the mains, faults can take a long time to clear. With fuse-saving, main-line faults are normally cleared in 5 to 7 cycles on the first shot with the instantaneous element. With fuse-blowing, this same fault may last for 0.5 to 1 second. Much more damage at the fault location can occur during this extra time. Some of the problems that have been identified are:

- Wire burndowns occur: The heat from the fault-current arc burns the conductor enough to cause it to break and fall to the ground.
- Damage to inline equipment occurs: The most common problem has been with inline hot-line clamps. If the connection is not good, the fault arc across the contact can burn the connection apart and cause it to break.

- Extra fault duty placed on substation transformers.
- Ground faults are more likely to become two- or three-phase faults.
- Faults on under-built distribution are more likely to cause faults on the transmission circuit above.

Of all the items on this bulleted list, wire burndowns problems are the most important consideration. Wire burndowns are usually a problem with the use of the following:

Covered wire: Covered wire (also called tree wire or weatherproof wire) will hold an arc stationary. Because the arc is stationary, burndowns will happen faster than with bare wire.

Small, bare wire for the mains: Small, bare wire (less than 2/0) is also susceptible to wire burndowns. This situation might exist if laterals are not fused.

Covered wire is widely used to limit tree faults. Several utilities have had burndowns of covered wire circuits when the instantaneous trip was not used or was improperly applied [5,[6]]. If a burndown on the main line occurs, it will be a long interruption for all of the customers on the circuit. In addition, it is a safety hazard. After the wire breaks and falls to the ground, the substation breaker may reclose. After the reclosure, the wire on the ground will probably not draw enough fault current to trip the station breaker again. This is a high-impedance fault that is extremely difficult to detect.

Covered wire is susceptible to burndowns because when a fault-current arc develops, the covering prevents the arc from moving. The heat from the arc is what causes the damage. Although ionized air is a fairly good conductor, it is not as good as the wire itself, so the arc gets extremely hot. On bare wire, the arc is free to move, and the magnetic forces from the fault cause the arc to move (in the direction away from the substation—a phenomenon called *motoring*). The covering constricts the arc to one location, so the heating and melting is concentrated on one part of the wire. If the covering is stripped at the insulators and a fault arcs across an insulator, the arc will motor until it reaches the covering, and the burndown can occur there. Lightning, a tree branch, or an animal can be the original cause of the arc. Burndowns are most associated with lightning-caused faults. (It's the fault-current arc, not the lightning that causes the damage.)

Using a fuse-blowing scheme can increase burndowns because the fault duration is much longer on the time-delay relay elements than on the instantaneous element. The wire damage is a function of the duration of the fault and the current magnitude. Burndown damage characteristics are much lower than annealing curves that are published for conductors. As an illustration of the damage and the protection provided by the time-delay relays, Figure 4-8 shows the threshold of damage for 336.4-kcmil, covered, all-aluminum conductor (data from [[7]]). The relay curve shown is a ground relay using a CO-11 (extremely inverse) with a time dial = 5 and a pickup =

[6] P. P. Barker and T. A. Short, "Findings of Recent Experiments Involving Natural and Triggered Lightning," panel session paper presented at 1996 Transmission and Distribution Conference & Exposition, Los Angeles, CA, September 16-20, 1996.

[7] R. E. Lee, D. E. Fritz, P. H. Stiller, L. A. Kilar, and D. F. Shankle, "Prevention of Covered Conductor Burndown on Distribution Circuits," American Power Conference, 1980.

300 A. An instantaneous relay characteristic is also shown. The instantaneous element will protect the wire up to approximately 4000 A. If the instantaneous element is removed (to use a fuse-blowing scheme), the ground relay will not protect the wire from damage for any current level. The burndown damage curve shown is the threshold of damage—an actual wire breakage will be higher than this by some amount.

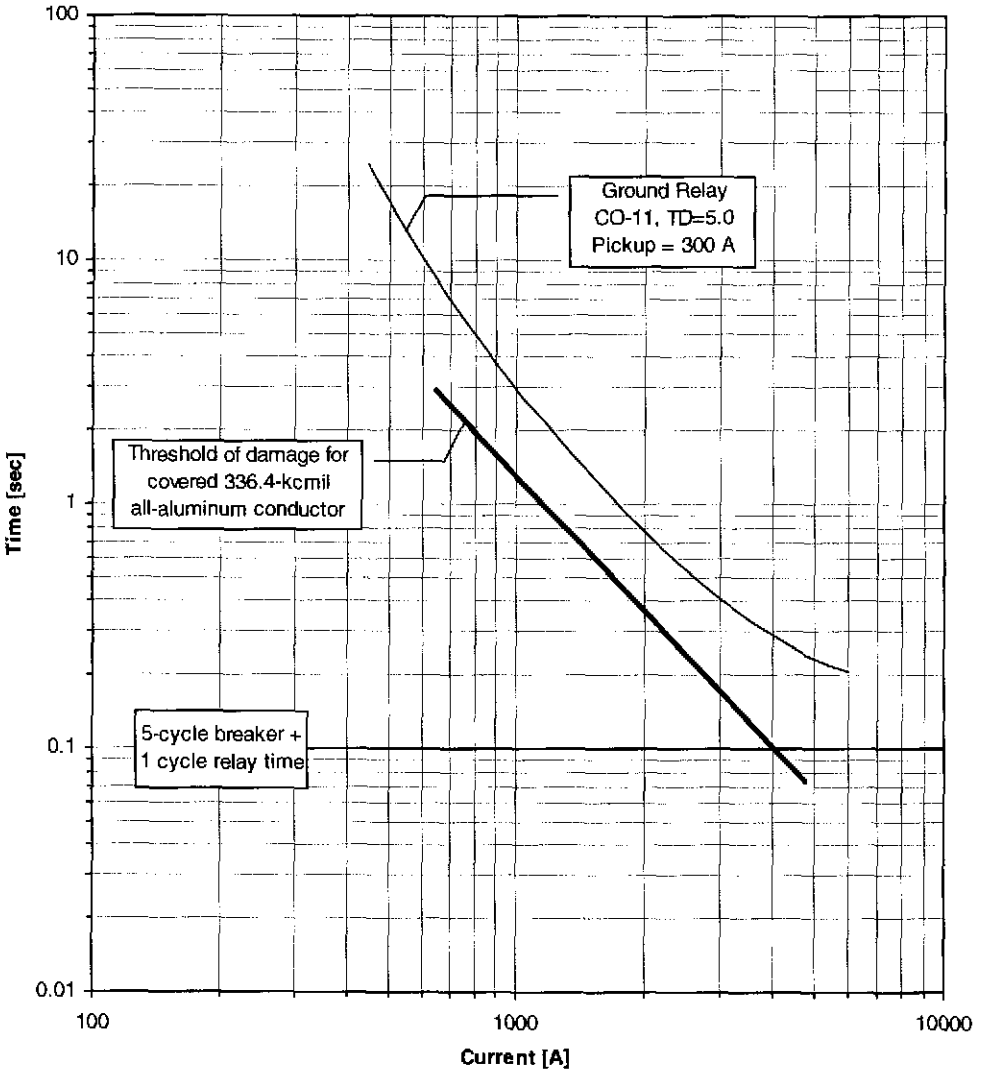


Figure 4-8
Burndown Threshold of Damage Compared to Typical Relay Characteristics

If covered wire is used, the solutions include:

- Use fuse-saving.
- Use arc protective devices (APDs): APDs are sacrificial masses of metal attached to the ends of the conductor where the covering is stripped [7].

- Use a delayed instantaneous operation for fuse-blowing rather than removing the instantaneous operation (discussed in a later section titled "Time Delay on the Instantaneous Element [Fuse-Blowing]").
- Use a high-set instantaneous curve for fuse-blowing rather than removing the instantaneous: Instead of eliminating the instantaneous, set it to trip for faults within the first mile or so of the substation to trip quickly for high-magnitude faults (which are more likely to cause burndowns).

Although not as susceptible as covered wires, bare wires can also have burndowns. Figure 4-9 shows burndown damage information for all-aluminum alloy conductor (AAAC) bare wires along with a 100-K lateral fuse element and the same ground relay element used above. The fuse protects the wires shown, but the ground relay does not provide adequate protection for wires smaller than #2 AAAC. All-aluminum conductor (AAC) is expected to be slightly worse because the AAAC has a higher breaking strength. The solutions for small bare wire are:

- Fuse lateral taps
- Use fuse-saving
- Use a delayed instantaneous for fuse-blowing
- Use a high-set instantaneous

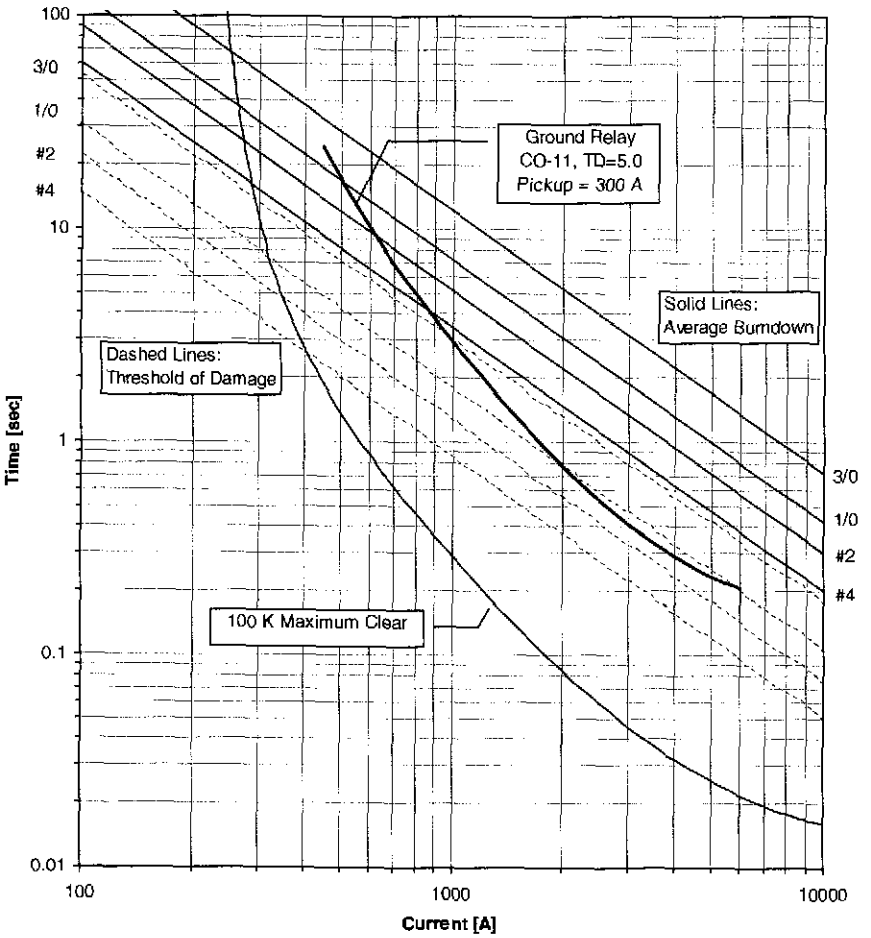


Figure 4-9
Bare-Wire Burndown Curves for All-Aluminum Alloy Conductor Along With a 100-K Lateral Fuse and a Ground Relay Element [8]

Long-Duration Voltage Sags With Fuse-Blowing

One of the disadvantages of a fuse-blowing scheme is that voltage-sag durations are longer for temporary faults. This observation is especially true for faults on the three-phase mains that have to be cleared by a phase or ground time-delay element. An example is shown in Figure 4-10 where voltage sag magnitudes and durations are shown for faults at 0, 0.5, 1, 1.5, ... miles from the substation using a fuse-blowing scheme. For the same circuit with a fuse-saving scheme, all of the faults would have cleared in 0.1 seconds. For a fault at the substation, the duration is tripled. For a fault that is 1 mile from the substation, the duration is quadrupled. The situation is worse for phase-to-phase faults and three-phase faults, because they must be cleared by the phase relays, which are generally set higher.

[8] J. A. Lasseter, "Burndown Tests on Bare Conductor," *Electric Light and Power*, pp. 94-100, Dec. 15, 1956.

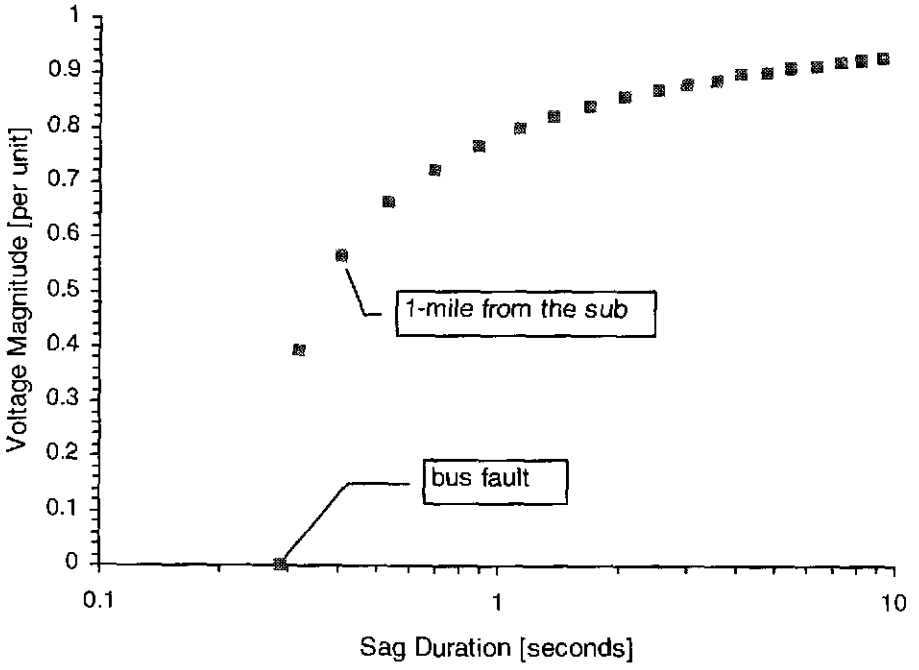


Figure 4-10
Magnitudes and Durations of Substation Bus Voltage Sags for Ground Faults Applied Every Half Mile on a 12.47-Kv Circuit With a Fuse-Blowing Scheme. The Faults Are Cleared by a Ground Relay (CO-11, TD = 5, Pickup=300A). For the Same Circuit With a Fuse-Saving Scheme, All of the Faults Would Have Cleared in 0.1 Seconds

Optimal Implementation of Fuse-Saving

To get a fuse-saving scheme to work, it is necessary to get the substation protective device to open before fuses blow. This can be achieved in several ways:

- **Slow down the fuse**: Use big, slow fuses (for example, 140-T or 200-T) near the substation to ensure proper coordination.
- **Use faster breakers or reclosers**: If three-cycle breakers are used instead of the normal five-cycle breakers, fuse-saving coordination is more likely. Reclosers are even slightly faster than a three-cycle breaker.
- **Limit fault current:**
  - Open station bus ties: An open bus tie will reduce the fault current on each feeder and make fuse-saving easier. This practice is the normal operating mode for most utilities.
  - Use a transformer neutral reactor: A neutral reactor will reduce the fault current for single-phase faults.

- Use line reactors: This practice will reduce the fault current for all types of faults. The use of line reactors, however, has been an uncommon practice. It has the added advantage of reducing the impact of voltage sags for faults on adjacent feeders.
- Specify higher-impedance transformers

Other strategies can also be employed to limit the impact of momentary interruptions:

- **Use more downstream reclosers**: Extra downstream devices will reduce the number of momentaries for customers near the substation. It is important to coordinate reclosers with the upstream device (including sequence coordination).
- **Use single-phase reclosers:** Single phase reclosers on three-phase circuits reduces the number of customers affected by single line-to-ground faults.
- **Use instantaneous reclosers:** Instantaneous reclosers can limit or reduce the effect of momentary outages on customer equipment by reducing the amount of time the feeder is open. This option can have negative impacts on motors.
- **Switch to a fuse-blowing scheme on poorly performing feeders**: For a feeder with many momentaries, the instantaneous relay can be disabled for a time period. Poorly performing sections of the circuit can be identified during this time. Once the poorly performing sections are identified and improved, the circuit can be switched back to a fuse-saving scheme.

Optimal Implementation of Fuse-Blowing

Several strategies can optimize a fuse-blowing scheme:

- **Use fast fuses or current-limiting fuses**: If fuse-blowing is used, no need exists to try and use big, slow fuses. If smaller or faster fuses are used, the fault will be cleared faster, so the voltage-sag duration will be shorter. Note that fuses should not be too small, or nuisance fuse operations will occur because of loading, inrush, and cold load pickup.
- **Covered wire or small wire**: Watch burndowns on circuits with covered wire or small wire that is protected by the station breaker or recloser. If either of these cases exists, then it is recommended that a modified fuse-blowing scheme with a time-delayed, instantaneous element be used (see the next section entitled "Time Delay on the Instantaneous Element [Fuse-Blowing]").
- **Use single-phase reclosers on longer laterals**: A good way of maintaining some of the reliability of a fuse-saving scheme is to use single-phase reclosers instead of fuses on longer taps. Then temporary faults on these laterals will not cause permanent interruptions to customers on these laterals.
- **More fuses**: Another option is to add more second- and third-level fuses to laterals to further segment the circuit.
- **Track lateral operations**: Temporary faults on fused laterals will cause sustained interruptions. To minimize the impacts on lateral customers, it is beneficial if interruptions are tracked by lateral. Poorly performing laterals can be identified. Poorly performing sections can be patrolled, trees trimmed, animal guards installed, and other similar actions.

Time Delay on the Instantaneous Element (Fuse-Blowing)

An alternative implementation of a fuse-blowing scheme is to use a time delay on the instantaneous trip (rather than removing it) [9]. This practice has the advantage that faults do not last as long as they would if the relay went to a time-delay element. This reduces the chance of wire burndowns, and it reduces the duration of voltage sags for faults on the mains. A common delay is 0.1 seconds.

An example implementation is shown in Figure 4-11 where a 0.1-second delay is added to the instantaneous operation. A 100-K fuse link is also shown in Figure 7-7. For the 100-K link, the scheme is actually a mixture of fuse-saving and fuse-blowing. For fault currents greater than roughly 1700 A, it is a fuse-blowing scheme (the fuse will clear before the instantaneous relay operates). For currents less than 1000 A, the scheme is a fuse-saving scheme (the breaker will trip before the fuse is damaged). Between 1000 and 1700 A, one or both devices may operate.

Another option that is sometimes used with this scheme is to use a high-set instantaneous along with the delayed instantaneous. The high-set instantaneous would have no delay and be set to clear faults close to the station. This will remove the most damaging faults quickly (because they are the most likely to cause damage and cause the most severe voltage sags).

[9] N. G. Engelman, "Relaying Changes Improve Distribution Power Quality," *Transmission and Distribution*, pp. 72-76, May 1990.

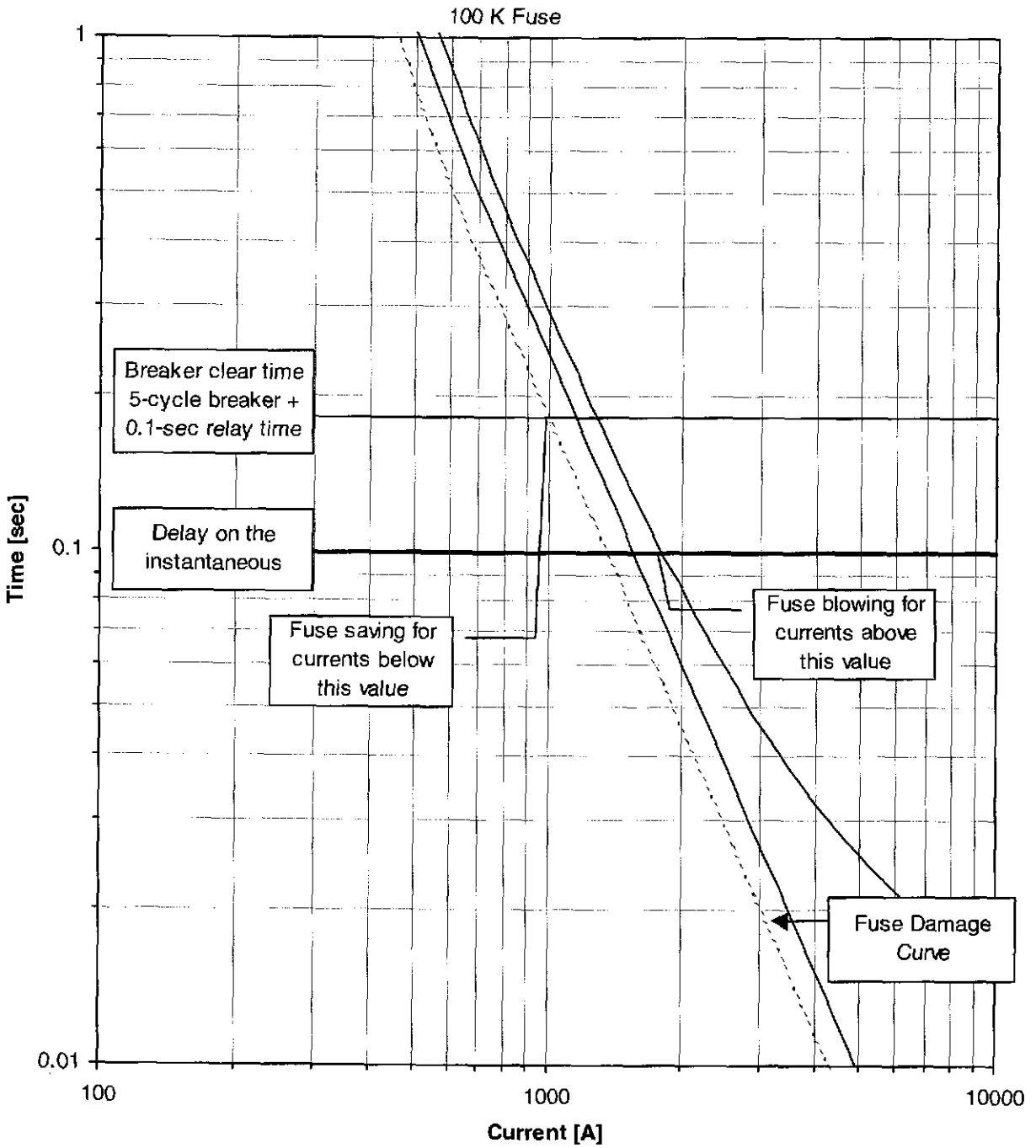


Figure 4-11
Example of a Delayed Instantaneous Element Used for Fuse-Blowing

Using a delay is a better fuse-blowing scheme than just removing the instantaneous. The disadvantage, and the reason that it may not be implemented as much, is that it is usually more difficult and costly to implement. For electromechanical relays, another timer relay must be added, and the relay scheme must be engineered. Many digital relays have this option available, so in that case it would be much easier to implement.

High-Low Combination Scheme

Another option is to use fuse-blowing at the substation and fuse-saving at downstream reclosers. The rationales for these choices are:

- Fuse-blowing at the substation: Fault currents are high near the substation, so it is difficult to get fuse-saving to work here
- Fuse-saving at downstream reclosers: Fault currents are lower downstream, and reclosers are faster, so fuse-saving should work well here

This scheme is easy to implement. The station instantaneous trip would be eliminated. Reclosers would be operated with a fast trip (that is, the A curve)—most are already in this mode, so no changes would be necessary here.

Control of the Protection Scheme by a Supervisory Control and Data Acquisition System

Another option is to use a supervisory control and data acquisition (SCADA) system to change back and forth between fuse-saving and fuse-blowing. This is an attempt to get some of the benefits of both schemes. Fuse-blowing would be the normal operating mode, but human operators could switch to a fuse-saving scheme during storms. This would avoid clear-sky momentaries while at the same time improving storm restoration. Several factors make it better to use a fuse-saving scheme during storms:

- Faults are more likely to be temporary during storms (lightning, wind).
- Customers are more forgiving about momentaries during storms.
- Outages because of fuse operations last longer during storms (because crews have many repairs to perform). If fuses are blown because of temporary faults, this will increase the number of repair locations. Fuse-saving will reduce the number of outages crews will have to address.

For SCADA control of fuse-saving to be effective, the system will have to be designed for fuse-saving. This means using larger, slower fuses for laterals close to the substation, using faster breakers (or use substation reclosers), or possibly even using grounding reactors in the substation to limit fault currents. Likewise, the system would have to be designed for fuse-blowing. This would mean avoiding using tree wire (or go to a delayed instantaneous rather than removing the instantaneous trip).

Control is more readily available in the substation because the SCADA infrastructure may already be in place. If so, the cost of the SCADA system has already been justified, and this added functionality could be piggybacked on the existing system if there are free channels available. It is feasible to use automation technology to implement remote control of feeder reclosers, but the cost of the communication equipment probably would not justify having this functionality.

For SCADA control, microprocessor-controlled relays are not needed. A SCADA channel can be used to control a blocking relay on the instantaneous elements of the feeder relays. An alternative would be for the SCADA channel to control the delay on the instantaneous element—Option 1 is no delay (or fuse-saving); Option 2 has a delay (fuse-saving below a certain fault current); and Option 3 is inhibited instantaneous operation (or fuse-blowing). One SCADA channel could be used to control the fuse-saving/fuse-blowing status of all of the distribution feeders in a station. Alternatively, each feeder could be controlled independently.

Adaptive Control by Phases

Various protection schemes are classified as adaptive. An adaptive approach to a fuse-blowing mode is to adjust the scheme depending on how many phases are faulted:

- Two- or three-phase fault: Use the instantaneous—the fault is assumed to be on the three phase mains. By tripping quickly, this will reduce the duration of voltage sags for faults on the mains.
- Single-phase fault: Use fuse-blowing (that is, use time-delay curves or delayed instantaneous relay).

This scheme would require microprocessor-based relays. This is not a common scheme, and the expense and complexity is not likely to justify it unless the chosen relays come with this functionality, and it is easy to configure the relay for this operation mode.

Fuse-Saving and Fuse-Blowing Summary

Fuse-saving has traditionally been used for two reasons: fewer blown fuses to replace, and improved reliability. The disadvantage of fuse-saving use is increased momentary outages for customers. When momentary outages become a major concern, particularly for customers connected to the main line, fuse-blowing may make more sense. Fuse-blowing will protect customers from momentary outages caused by faults on laterals. When implementing fuse-blowing, care must be taken to avoid situations that could result in conductor damage or burndown. One popular scheme is to use fuse-blowing for laterals between the station and the first downstream recloser, and fuse-saving for the remainder of the circuit.

Sequence Coordination of Reclosers

Most utility reclosers (or breakers) are programmed to open once (or twice) using a fast curve (known as a fast operation) and then open once (or twice) using a slower curve (known as a delayed operation) during a permanent fault. The most common setup is for two fast operations and two delayed operations before the recloser locks out. The recloser thus opens three times—allowing the fault to clear itself—and then opens a fourth time and locks out if the fault is still present. This system is meant to reduce the number of permanent outages from temporary faults. With two or more reclosers (or breakers) in series, it is possible for more than one device to respond to a given fault. This creates momentary interruptions on sections of the distribution feeder that are not faulted, thus degrading the quality of power provided to those customers.

Sequence coordination inhibits the fast tripping of all devices except the one immediately upstream from the fault, reducing the number of momentary interruptions experienced by customers on the feeder.

Standard Coordination and Its Effect on Momentary Interruptions

Standard coordination methods for reclosers can result in unnecessary momentary interruptions for customers not on the faulted zone of a circuit. Figure 4-12 illustrates what can happen for a faulted circuit with two reclosers, both with two fast and two slow operations. Recloser R2 (the device immediately upstream from the fault) is supposed to operate for faults in its zone. However, if the fault current is high enough, Recloser R1 (the next device upstream of Recloser R2) may also operate. This is because the fast curve of the upstream recloser is often faster than the slow curve of the downstream recloser.

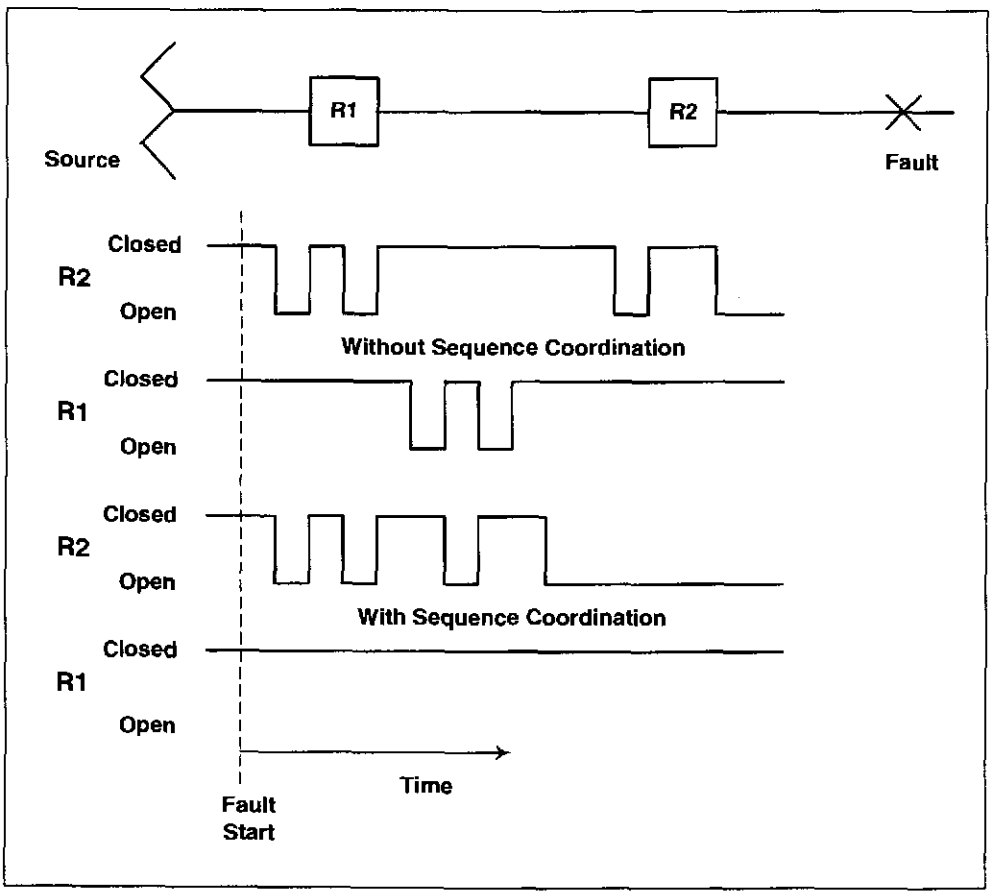


Figure 4-12
Performance of Reclosers With and Without Sequence Coordination

When the fault occurs, the closest upstream device (Recloser R2 in this case) operates on its fast curve. In this example, the fault is permanent. Therefore, R2 will reclose and then operate again on its fast curve. As the illustration shows, the next upstream device will operate twice on its fast

curve. This is because the fast curve for R1 is faster than the delayed curve of R2. Once R1 has operated twice on its fast curve, R2 will operate twice on its delayed curve and lock out.

Sequence Coordination and Its Effect on Momentary Interruptions

Many utilities are now attempting to create a "high-reliability zone" [10] for the section of the distribution feeder between the station and the first mainline protection device (that is, between R1 and R2 in Figure 4-12). High-reliability zones are created using a variety of techniques, including changing to a fuse-blowing scheme, using instantaneous reclose , using current-limiting fuses on laterals , and using sequence coordination. This high reliability zone is treated differently because an outage in this zone affects every customer on the circuit. Reducing the number of momentary and permanent outages in the high reliability zone can greatly increase the reliability of the entire circuit.

With sequence coordination, a protective device's fast curve is inhibited for a fault beyond the protection zone of the device if a downstream device opens first. In our example, Figure 4-12, tbe fault is outside of the protective zone of Recloser R1. The fault is in the protective zone of R2. With sequence coordination properly implemented, a permanent fault will result in the following sequence of operations:

1. R2 operates on its fast curve and recloses.
2. R2 operates a second time on its fast curve and recloses.
3. R1 inhibits its fast curves and does not operate.
4. R2 operates twice on its delayed curve and locks out.

In this example, sequence coordination prevents two momentary operations for the high-reliability zone of the circuit. With normal coordination, every customer on the circuit would have been subjected to two unnecessary momentary interruptions.

Comparison of Reliability

Using a simple circuit, it is possible to illustrate the difference in reliability performance in a circuit with sequence coordination. For this illustration, we will use a circuit with two protection zones, evenly spaced, and with equal number of customers in each zone (see Figure 4-13). For our calculations, we will assume that each zone experiences five permanent outages per year.

[10] Brian D. Coate and Don C. Wareham, "Decreasing Momentary Outages with Specific Distribution Feeder Improvements," *IEEE Transactions on Industry Applications*, Vol. 37, No. 2, March-April 2001, pp. 458–463.

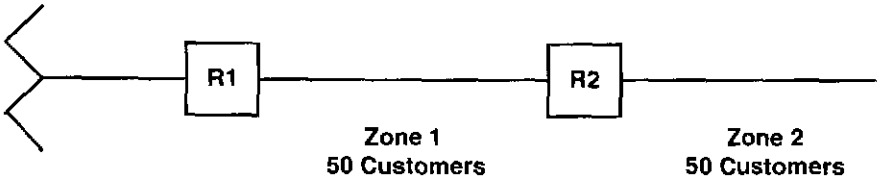


Figure 4-13
Example Distribution Circuit

Sequence coordination has the most effect on the Momentary Average Interruption Frequency Index (MAIFI). MAIFI represents the average number of times a customer is subjected to a momentary outage and is defined in Equation 1-1.

$$MAIFI = \frac{\sum ID_i N_i}{N_T}$$ **Equation 4-1**

where

i = interruption event,
T = total,
ID_i = number of interrupting device operations,
N_i = number of interrupted customers for each interruption event,
N_T = total number of customers served.

As you can see in Table 4-12, sequence coordination can eliminate up to two operations for Recloser R1 for each fault in Zone 2 of the circuit. This has a significant impact on MAIFI because an operation of Recloser R1 affects all 100 customers of the circuit.

Table 4-12
Number of Device Operations for a Fault in the Specified Zone Assuming Two Fast and Two Delayed Operations Before Lockout

Device	Fault in Zone 1		Fault in Zone 2	
	Without Sequence Coordination	With Sequence Coordination	Without Sequence Coordination	With Sequence Coordination
Recloser R1	4	4	2	0
Recloser R2	0	0	4	4

The MAIFI for this circuit (see Figure 4-13) without sequence coordination, assuming five permanent faults per year per zone, is calculated as follows:

First, calculate ID_iN_i for faults occurring in each zone:

Fault in Zone 1:

(4 operations × 100 customers for R1) + (0 operations × 50 customers for R2)
= 400 per event

This is multiplied by the number of events (five in this case) for a total of 2000.

Fault in Zone 2: $(2 \times 100) + (4 \times 50) = 400$
$400 \times 5 = 2000$

Now the ID_iN_i terms are added together and divided by the total number of customers served:

Sum of customer outage numbers = 2000 + 2000 = 4000

MAIFI = 4000/100 = 40 interruptions per year per customer

Similarly, the MAIFI for the circuit with sequence coordination is calculated as follows:

Faults in Zone 1: $[(4 \times 100) + (0 \times 50)] \times 5 = 2000$

Faults in Zone 2: $[(0 \times 100) + (4 \times 50)] \times 5 = 1000$

MAIFI = (2000 + 1000)/100 = 30 interruptions per year per customer

Using sequence coordination reduced the MAIFI for this circuit by 25%. Granted this is a simplistic example. However, the use of sequence coordination has been shown to significantly reduce MAIFI numbers and customer complaints in utilities.

Coordination Requirements

For sequence coordination to work, the fast curves of the two devices must be properly coordinated. Again, referring to the example circuit in Figure 4-13, Reclosers R1 and R2 must be properly coordinated. The control response curve of Recloser R1 must be slower than the recloser clear curve of R2 (that is, the control response curve of R1 must be above the recloser clear curve of R2). The control response curve is the curve representing the time it takes for the recloser control (or relay) to determine that there is a fault condition and send a trip signal to the recloser (or breaker). The total clear curve is simply the control response curve plus the amount of time it takes for the recloser (or breaker) to open once it receives a trip signal.

Figure 4-14 illustrates the coordination of the two reclosers in our example circuit assuming R1 has a trip setting of 200 A and R2 has a trip setting of 100 A. The R1 curve is the control response curve. The R2 curve is the recloser clear curve. As you can see, the devices only coordinate up to approximately 1500 A of fault current. For any fault greater than this, sequence coordination will not work properly and R1 will also open for faults in Zone 2.

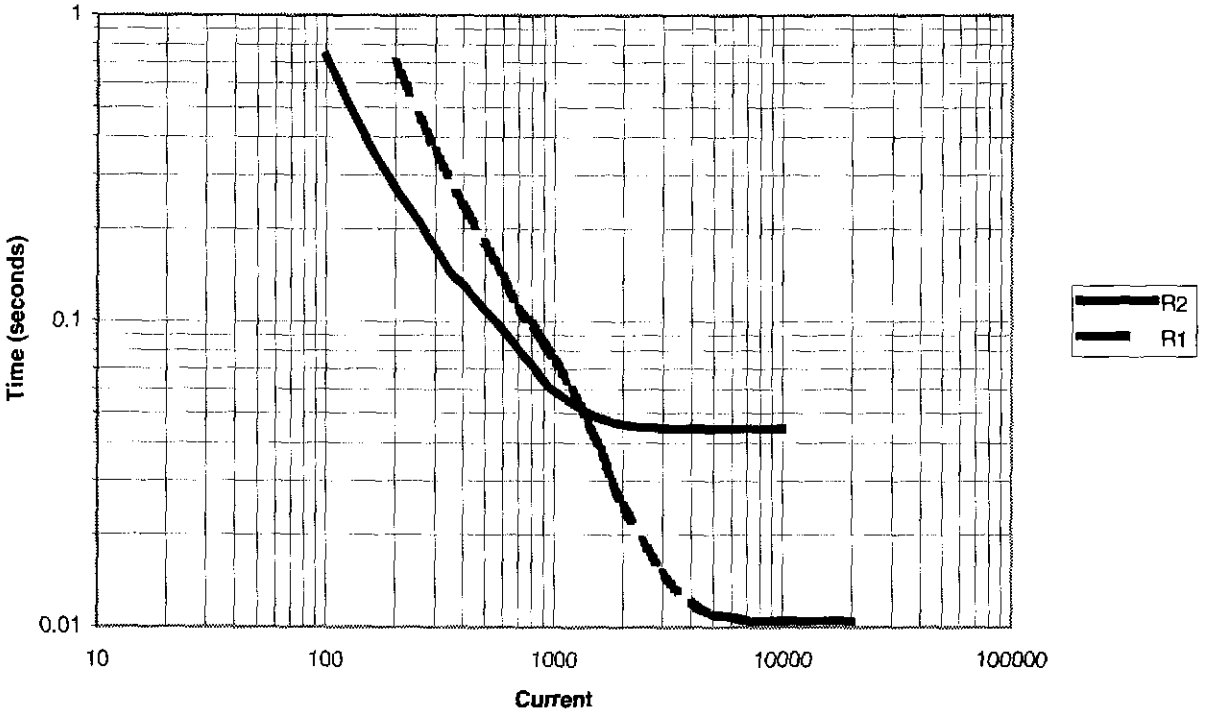


Figure 4-14
Coordination of the Fast Curves of Two Reclosers

There are many options for correcting this problem if necessary. Most recloser controls and relays offer several curves to choose from. Many also allow the operator to modify the curve to provide better coordination in this type of situation. One such option is "minimum response." Setting a minimum response time forces the control to wait at least that amount of time before sending a trip signal to the recloser or breaker. A minimum response setting of 0.06 seconds is illustrated in Figure 4-15. This setting would allow these reclosers to be coordinated for all fault currents and this would allow sequence coordination to work properly for all levels of fault current.

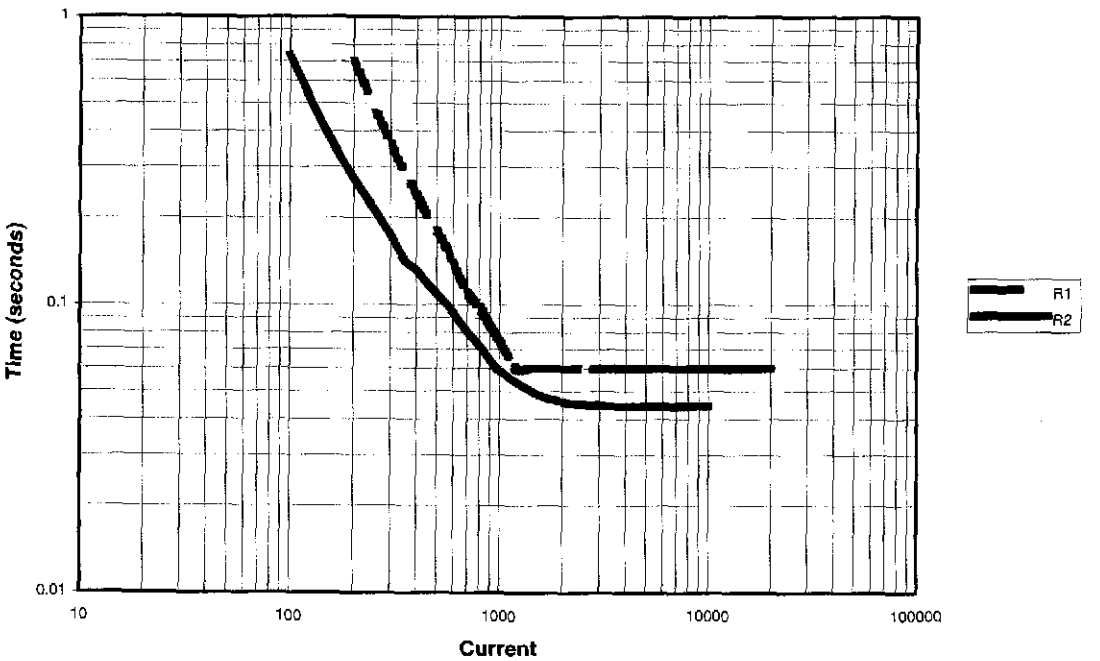


Figure 4-15
Coordination of the Fast Curves of Two Reclosers, One with Minimum Response Set to 0.06 Seconds

If the recloser (R2 in our example) is a hydraulic, single-phase recloser, both the phase and ground fast curves of the upstream recloser (R1 in our example) must coordinate with the downstream device's fast trip curve. More discussion of sequence coordination and the modification of trip curves can be found in *Electrical Distribution-System Protection* by Cooper Power Systems [[11]].

Sequence Coordination Summary

Sequence coordination can improve the reliability and power quality of a distribution circuit by reducing the number of momentary outages experienced by customers on the circuit. Sequence coordination is extremely effective at reducing the number of momentary outages experienced on circuit zones that are not faulted. The only requirements are that the upstream device must be electronically controlled (either a recloser control or a relay) and the fast curves of the two devices must coordinate properly over the entire range of expected fault currents. Coordination of the fast curves can be difficult for high fault currents. However, most controls allow for modification of the response curves to provide the necessary separation to allow proper coordination.

[11] Cooper Power Systems, *Electrical Distribution-System Protection* (3rd Edition), Cooper, 1990.

Coordination Summary

Circuit coordination techniques can greatly enhance the reliability of radial distribution feeders. This chapter presented an example circuit with poor reliability. Various coordination techniques, and their effect on reliability, were demonstrated. Adding feeder reclosing, lateral tap fuses, and a midpoint recloser, provided a significant improvement in the reliability of the feeder. This improvement was realized without requiring reductions in outage causes such as tree contact.

Two more advanced topics were also presented: (1) fuse-saving versus fuse-blowing and (2) sequence coordination. These techniques can be used to further enhance the reliability of a feeder. This chapter is should not be considered a complete primer on proper coordination of protective devices. *Electrical Distribution-System Protection* by Cooper Power Systems [11] is recommended as a primer on circuit coordination.

5
RELIABILITY SOFTWARE REVIEW

The purpose of this chapter is to provide a review of the capabilities of the SynerGEE® Reliability module, produced by Stoner Associates, Inc. The three client utilities use SynerGEE Electric to analyze their distribution systems. The recent release of this tool, which is an add-on to the SynerGEE Electric system, adds the ability of analyzing the reliability of distribution feeders to the long list of existing features of the current software package.

Features of SynerGEE's Reliability Module

Much of this text detailing the features of the Reliability Module comes directly from SynerGEE technical literature for this product. I have added comments on usefulness and benefits when appropriate. Perhaps the most important feature from the standpoint of usability is the fact that it works on the SynerGEE platform, which is familiar to the client utilities.

Common Environment

SynerGEE Reliability operates off of a standard electric distribution model stored in a totally open database. The same model that is used for reliability is also used for other SynerGEE applications including:

- Load-flow
- Fault flow & fault voltage
- Contingency
- Optimal switching
- Phase balancing
- Harmonic analysis
- Capacitor analysis
- Coordination checking
- Time range load analysis

Several stand-alone reliability analysis packages are on the market today, however, Stoner believes that reliability cannot be engineered in a vacuum. Voltage support, contingency, power quality, capacity, and efficiency are just a few of the considerations that have to be made by utility engineers. It is up to the engineer to ensure that the system is designed in a secure and

expandable fashion while providing for improvements in reliability. Therefore, reliability must be studied along with the systems performance in these other areas. Figure 5-1 shows the output of several SynerGEE modules used to analyze a single feeder.

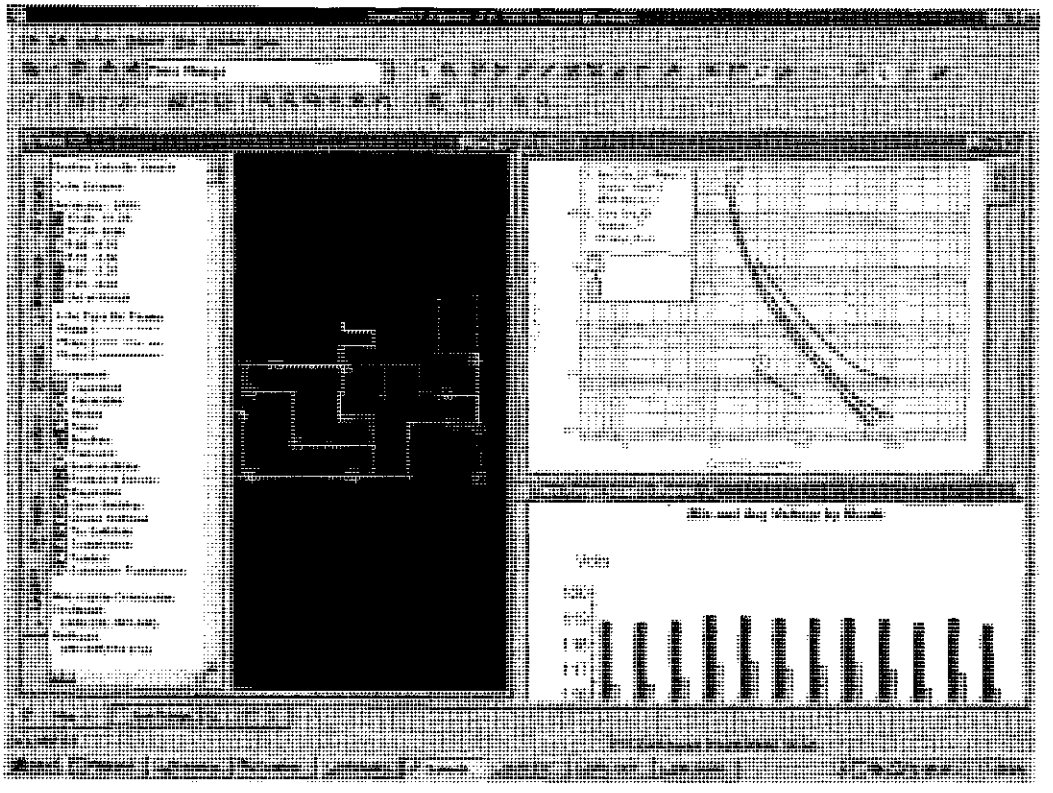


Figure 5-1
Example Output of SynerGEE Showing Results from Reliability, Coordination, and Load Flow Modules

There are two major benefits to using a common platform: data entry requirements are reduced, and training requirements are minimized. While additional entry of reliability specific data is required, the Reliability module works off of the existing SynerGEE feeder models. This reduces the amount of data entry required when compared to a stand-alone reliability product. Another benefit of using a common platform involves training. Because this product works on a platform familiar to the utilities, the training needs to get to the point of productively using the software will be minimized.

SynerGEE Reliability Module Capabilities

SynerGEE Reliability is a comprehensive package to aid in the simulation and analysis of distribution system reliability. Delivered on the SynerGEE platform, it is a powerful tool for investigating root-cause and configuration effects on system and customer level reliability. SynerGEE Reliability has the following characteristics:

- Zone-based failure rates, repair times, and repair costs with provisions for single- or three-phase lines.

- Use of failure rates based on historical outages
- In depth root-cause analysis
- Comprehensive and detailed switching models
- By-phase analysis
- By-cause analysis
- Sectionalizing, reclosing, pickup
- Capacity evaluation
- Unlimited and customizable causes
- Failure rates by category and subcategory.
- Mitigation over multiple subcategories
- Comprehensive contingency-based interruption, switching, and pickup plans
- By-phase analysis and results reporting
- Handling of automatic switches and auto-transfer switches

Required Data

The data required for SynerGEE Reliability is:

- A load flow model including line sections, loads, switches, capacitors, protective devices etc.
- Historical failure rates and root cause data for line sections and equipment, this data can be implemented and analyzed at the feeder, protected sections, or individual line section depending on the quality of the available data
- Information on mitigation zones (optional)

Exposure Zones and Failure Rates

Sections with similar failure causes, geography, foliage, age, and construction can be grouped into an exposure zone. Sections assigned to a particular exposure zone are given common values for:

- Sustained failure rate per set length of line
- Momentary failure rate per set length of line
- Repair cost
- Repair time

The values in an exposure zone are itemized by cause category and subcategory. When you define exposure zones, SynerGEE draws categories and subcategories from the ReliCauseMeta.txt file, and you apply failure information to them as needed. This information is

grouped according to single-phase and two/three-phase lines. Once your exposure zones are defined, each section can be assigned to any zone. Zones can be set up geographically to account for similarities in construction, location, history, and terrain.

Exposure zones can also be set up to correspond to interrupting device, which allows a more direct application of historical outage data. You would probably construct zones in this manner if your outage data is assigned by interrupting device.

The SynerGEE exposure zone provides a means of applying multiple causes to whole regions of your system, and varying degrees of each. It also allows the correlation of lines with similar construction, in like areas, and with common isolation devices. For example, you may have a region in which squirrels, snakes, and deciduous trees are a problem. In SynerGEE, you can create an exposure zone that represents these causes, and apply it to sections in your model as appropriate.

Mitigation Zones

From a data perspective, mitigation is managed in a manner similar to exposure zones. Every section can be assigned to a mitigation zone. Mitigation zones are composed of causes and the impact of the mitigation on those causes. You can assign a percentage of mitigation effectiveness to each cause in the zone. Like exposure zones, categories and subcategories for causes are drawn from the ReliCauseMeta.txt file. Generally, the mitigation on most causes will be zero for a particular zone. However, keep in mind that some mitigation efforts can affect multiple causes. For example, squirrels, birds, trees, and other causes may be partially mitigated through tree trimming.

Results

Reliability simulation results are presented in a simple and comprehensive format within SynerGEE. Web based reports, charts, and maps are used to depict issues regarding reliability. Figure 5-2 shows one form of output available from SynerGEE Reliability. The feeder segments are color coded according to their reliability as calculated by the Reliability Module.

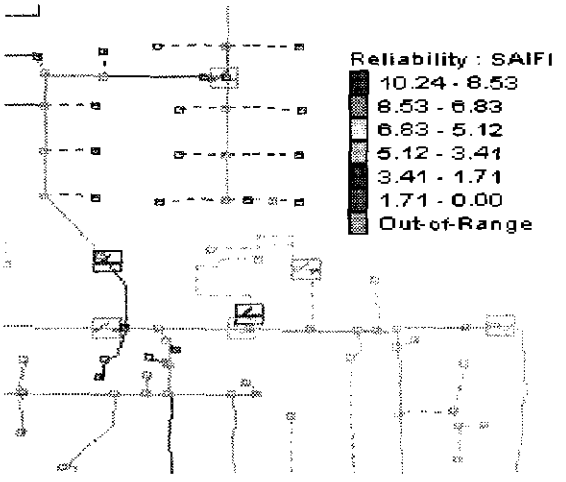


Figure 5-2
Reliability Results Colored by Reliability Results

Reliability simulation is a statistical analysis of a distribution system model. SAIDI, SAIFI, and other metrics are random variables. It is critical that the engineer be provided values of variance along with the metrics resulting from the analysis. An example of this statistical analysis is shown below in Figure 5-3.

Feeder	Cust Count	SAIFI	SAIDI	MAIFI
System	10920	4.1 +/- 1.0	10.3 +/- 2.8	6.1 +/- 1.4
New - Big Spring	1616	6.8 +/- 2.6	20.5 +/- 8.5	0.0 +/- 0.0
New - Cove	860	3.6 +/- 2.4	13.9 +/- 10.6	0.0 +/- 0.0
New - Liberty	1213	1.3 +/- 1.1	2.7 +/- 2.8	2.2 +/- 1.8
New - Springfield	1704	2.0 +/- 1.5	5.1 +/- 4.0	6.0 +/- 2.3
Ship - South Penn	1768	4.5 +/- 2.3	10.5 +/- 6.1	9.0 +/- 3.4
Ship - West Martin	3769	4.8 +/- 2.3	9.8 +/- 5.9	10.0 +/- 3.6

Figure 5-3
Tabular Output of the Reliability Module

Key Benefits of Using the SynerGEE Reliability Module

Below is a list of key benefits associated with using the SynerGEE Reliability Module. These are benefits identified by Stoner, the publisher of SynerGEE.

- SynerGEE lets you define the level of detail to model. If you have by phase, by cause data at the line section level, SynerGEE will take advantage of that. If your data is at the circuit level without phase information and only general causes, SynerGEE can work with that as well.
- Root cause analysis is key to determining what improvements should be made, SynerGEE lets you use your level of detail and allows you to define and analyze mitigation for any improvement.

- The confidence interval calculation provides insurance that the analysis has statistical significance.
- SynerGEE has repair, outage, and mitigation costs that can be set by the end user to analyze the potential economic impact of reliability improvements.
- SynerGEE Reliability uses all of the sophisticated device models (autotransfer switches, backfeeding regulators etc.) that the load flow program contains. This allows both reliability and planning engineers to work on the same model using the same set of editing tools to plan system improvements.
- SynerGEE is equipped with two reliability engines. One performs direct analytical analysis using historically based failure rates. The second performs a multi-year projected sample based analysis. Both types of analysis operate on the same model in the same environment. They both are by-phase and use the load flow model and available devices to simulate fault interruption, isolation, island pickup, and reconfiguration.
- SynerGEE is built on an open database structure and lets you load data either directly to the database or with built in tools that can define the failure zones.

Reviewers Impressions

We are new to SynerGEE Electric with only a few months experience. After creating a feeder model, we were able to easily add reliability data and begin analyzing the predicted reliability of the feeder. We focused our analysis on the effects on reliability of different coordination techniques. With few exceptions, we found the Reliability module to be quite intuitive. We were able to produce useful results with little difficulty. It is our opinion that someone with a good understanding of the SynerGEE system will have little trouble using the Reliability Module to produce valuable data for the planning of reliability improvements to their distribution system.

6
VEGETATION MANAGMENT

As the reliability study progressed, it was recognized that an operational area where the three client utilities could benefit greatly would be vegetation management. It was decided that vegetation management should be included in the scope of work.

Vegetation management is particularly important to the calculations of the reliability indices that are important to the utilities with the demands of deregulation. The relationship is shown in Figure 6-1 below.

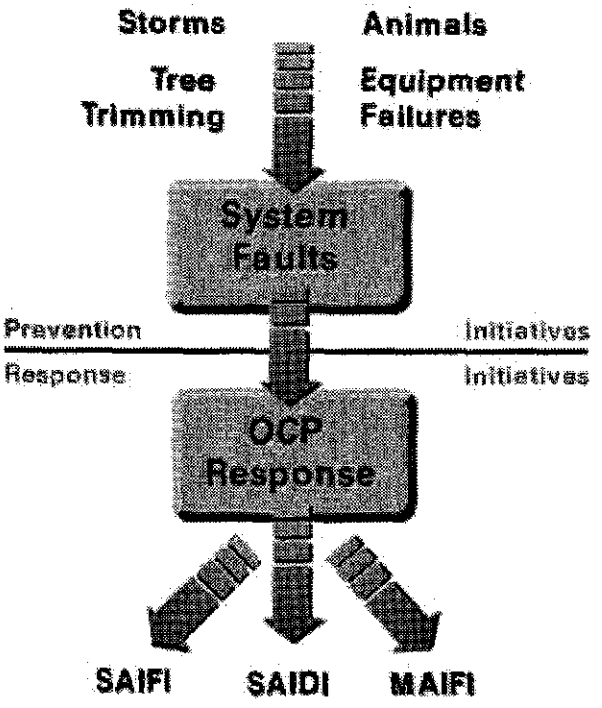


Figure 6-1
Relationship Between Vegetation Management and Reliability Indices

Cost Effectiveness of Vegetation Management

When considering vegetation management as a major contributor to reliable operations, it must be recognized that it is one of the most cost-effective areas where expenditures can be made that strongly impacts overall system reliability (and thus impacts reliability indices). This is clearly shown in the Table 6-1 below.

Table 6-1
Cost Effectiveness Comparison (from U.S. data)

Cost Effectiveness Comparisons

Program	$/cust-min
• Additional Tree Trimming	0.01
• Faulted Circuit Indicators	0.01
• SCADA with Breaker Control	0.05
• Infrared Inspection	0.66
• Reclosers/Sectionalizers	1.00
• Lightning Protection	1.20
• URD replacement	1.50
• Additional Switches	2.00
• Distributed Generation	3.40
• Feeder Automation	5.00

When considering budgets to improve reliability, vegetation management should be one of the first candidates. However, it is important to note that this is usually classified as an operating expense rather than a capital expenditure. Capital expenditures on trucks and cutting equipment are the major exceptions.

Tree-Trimming

Trees and branches are often a major factor in service outages, including those sometimes described as caused by storms/severe weather.

Tree-trimming is probably the largest and most controversial aspect of vegetation management from the point of view of the customer and environmental parties. It is also one of the areas where the impact is greatest on the reliability of distribution systems.

The economic benefits and impact on reliability indices are shown in the Figure 6-2 below.

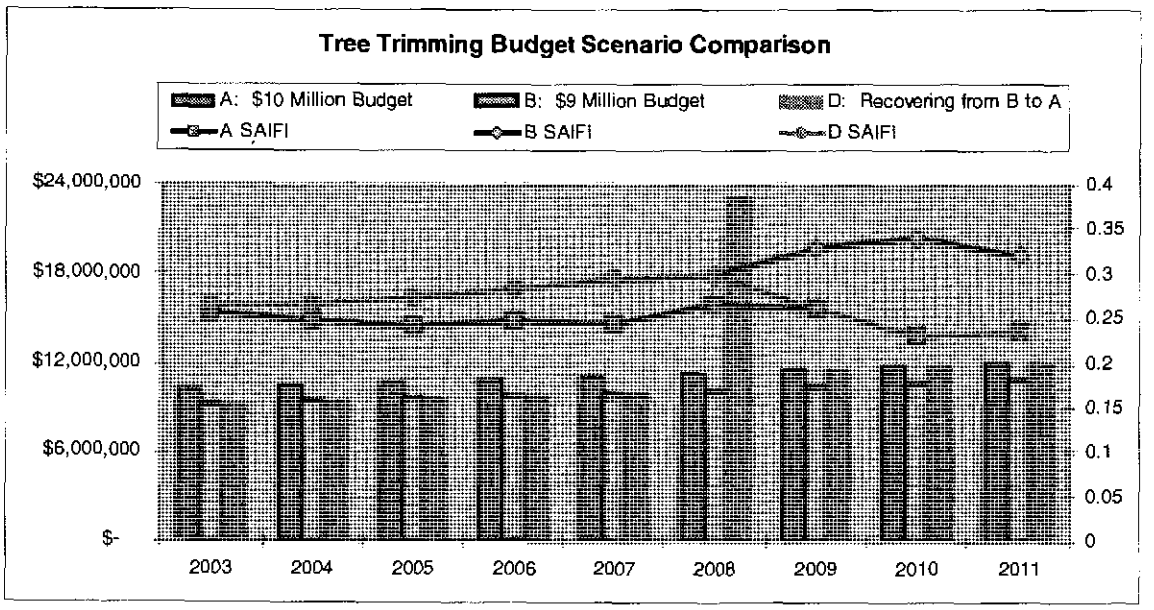


Figure 6-2
Tree Trimming Budget Scenario Comparison (from U.S. data)

Safety and Regulation

When considering vegetation management in relationship to reliability, one should also keep in mind its importance to maintaining electric safety standards. The utilities should also be cognizant of the possibility that regulating authorities might institute performance standards for vegetation management.

As deregulation approaches, caution must be taken that increased competitive pressures do not lead to reduced expenditures or preventive maintenance, such as tree trimming.

Description of Vegetation Management Activities

Vegetation management activities revolve around managing the vegetation growth around electrical power lines to reduce the interruption of service caused by tree contact. It also helps to contain costs that may arise from interruption of service and the effects of reduced power quality (for example, damage to electrical equipment), and minimizes maintenance costs.

Vegetation management services include:

Vegetation Management Program Analysis

Policies and procedures

Work specifications and scheduling

Record keeping

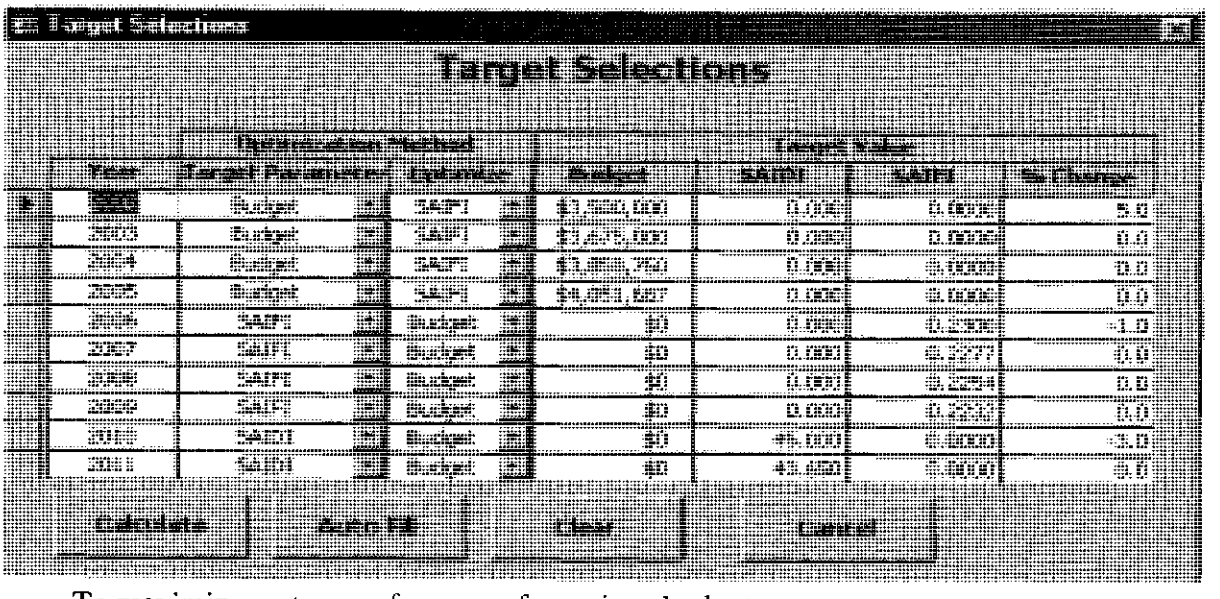
Public Relations (customers and regulators)

Recommendations

Cost Benefit Model

A model has been developed by Davies Consulting that analyzes the value of expenditures on tree-trimming using circuit data, outage data, and tree-trimming data (Appendix G). It analyzes this data, taking into consideration circuit length, number of customers, last trim year and critical circuits. From this analysis it develops cost and performance curves (interruption per mile/customer minutes out per mile) and creates a tree-trimming model. The model recommends a budget allocation and relates it to reliability.

A sample of the model is shown in the table below.



To maximize system performance for a given budget
To minimize the costs to achieve target reliability performance (SAIFI or SAIDI)

Specifications

It is recommended that the utilities develop specifications, standards and procedures for vegetation management. These should be prepared with reference to the impact on system reliability. These should be prepared with reference to the ANSI A300 Tree Pruning Standard, which provides guidelines for writing comprehensive specifications for vegetation management.

Vegetation Management Program

The three utilities should formalize their vegetation management programs by implementing the following program management tools:

- Design a system to evaluate and track crew productivity and performance
- Develop procedures and work specifications
- Provide on-site assistance in program implementation
- Provide training for staff
- Initiate best management practices
- Conduct Vegetation surveys
- Identify and record workload and work restrictions

A Vegetation Management Services staff should be developed to educate management staff, the public, government agencies and environmental groups regarding the value of professional vegetation management, and adherence to best practices. They should also be articulate in demonstrating the impact on reliability.

EPRI DRIVe Program

The three utilities should consider purchasing from EPRI the Distribution Reliability Indices for Vegetation (DRIVe) program (Appendix H). It is designed to schedule tree trimming around electric power distribution feeders in a way that optimizes the reliability of the system. Tree trimming affects the failure rate of line segments in the distribution system, which in turn affects reliability delivered to the customer. The tree trimming schedule problem is a difficult optimization problem that has been approached with an advanced optimization method involving its reliability cost and its cost of implementation. The expected reliability of a given tree-trimming schedule involves the following four steps:

1. A tree failure rate model is used to predict feeder segment failure rates as a function of the trimming schedule.

2. A reliability assessment model is used to calculate customer reliability from the component failure rates.

3. Customer reliability is used to calculate reliability indices.

4. The reliability indices are combined to determine the reliability of the design.

This application primarily calculates the reliability indices of the various components of the system using the Normal Reliability Assessment Module (NRAM). NRAM uses component failure rates and system topology information to calculate customer reliability. Both sustained

and momentary reliability is calculated. Various post fault switching options can be selected for the module.

7
OUTAGE MANAGEMENT

Outage Management System – Basic Elements

Objective

From the information technology viewpoint, an outage management system (OMS) should integrate several standard systems, such as a geographic information system (GIS), a trouble call system (TCS), a system control and data acquisition system (SCADA), and a customer information system (CIS). The objective should be to develop an OMS that provides accurate and relevant data and can easily be integrated with other system components. The system should be presented to the user in graphical form to aid in planning and repair actions.

Introduction – Importance of Data

Accuracy, timely data, and information collection systems are necessary preconditions for any OMS. Without them, when outages occur, it would be impossible to identify the causes and location of the system component in need of remedial actions. Data and information systems provide for the accurate identification and location of faulty components and permit timely system repair and restoration of normal operations. Effective repair and restoration work requires knowledge of (1) the electrical network and its reliability history, (2) the design, properties, and condition of the devices and equipment along the line, and (3) knowledge of monitoring equipment condition.

The Outage Management System is only as good as the data provided.

The consequences of inaccurate data are:

- Inaccurate prediction
- Inaccurate counts for number of customers affected
- Inaccurate measurement of consumer-hours of outage
- Invalid indices: SAIDI, SAIFI, and MAIFI

It is crucial to keep in mind that the outage management system helps to collect the data needed for calculation of the reliability indices. This is a very high priority for the three utilities with the advent of deregulation.

General

The three utilities tend to have similar concerns with respect to information technology. They depend upon computer systems for managing their maps using some kind of GIS systems. SCADA systems for remotely managing substations and main switches are deployed to a certain degree. They have TCSs that log the calls of customers reporting outages. The difficulties come when these systems have to work together, for example in the control room during an outage. A dispatcher watches the trouble call and SCADA systems and coordinates the repair actions of the crews. The dispatcher is actually performing much of the work of integrating and fusing information together and manually synthesizing the solutions. It is possible to support these tasks manually but not very efficiently. Optimum response requires systems that are designed to perform the integration and synthesis automatically. The solution synthesis also needs to be supported with appropriate tools. However, these tools and the resources to implement them are not readily available. One utility has dedicated the resources to partially develop such systems internally. Two others have relied on a combination of internal resources and outside programs and solution providers. Not only is the initial cost high, but also the cost of maintaining, upgrading, and evolving custom software is subject to resource constraints. The result is that many of the processes are performed manually by experienced staff.

The problems of improving OMS, and in general integrating the available data systems together in support of important decision making processes need to be resolved in a cost-effective and general way. The utilities need be able to use and maintain these systems more independently and inexpensively, especially in light of the current deregulated environment.

GIS Benefits Across the Enterprise

GIS should be considered as more that the geographical representation and digital storage of the utility's assets and their location. Integrating IT functions with a wide range of GIS-based systems, from facility maps to work management, can provide the enabling tools to support many utility processes, resulting in more efficient design, construction, operation and maintenance as well as improved customer satisfaction. To better understand the value of this approach to the utility, a comparison with the traditional uses of GIS would be helpful.

Existing Utility GIS

All utilities are highly concerned with the efficient and effective use of assets. Work associated with utility assets is 80 percent geospatial in nature, i.e. related to a point on a map or in space. Hence, GIS functionality in utilities evolved as automated mapping/facilities management (AM/FM). Initially, manual mapping simply recorded asset locations. Later systems performed basic modeling of real-world networks for analysis and planning, and they included a database to store attributes. Only in limited cases were these programs and databases integrated with other databases and applications managed by the IT department.

These systems are presently departmental solutions, used primarily by the engineering department. An enterprise focus does not exist at the moment.

Transition to an Enterprise View

AM/FM databases are too costly to be only departmental solutions, especially if multiple departments wanted to build them on separate technology platforms. Data standards gained importance, and data were leveraged among common applications and shared across the enterprise to reduce costs as a prerequisite for GIS project approvals. Geographically integrated work-management applications can be used to support design and construction processes, contributing data generated from asset records, customer location information, maintenance, distribution planning, taxation and other sources. A GIS-based outage management system will allow the utility to dispatch crews more effectively and restore service faster than ever before.

GIS-based IT should be seen as a major enabler of asset-related work processes. This is another reason to take an enterprise view, as processes are common across functional departments. Also, operational processes in areas such as field switching, crew dispatch and outage restoration can be considerably facilitated by GIS-based IT systems.

The GIS-based IT system that can be consider enterprise scale has the elements discussed below.

Service Restoration

In deregulated environment, customer relations are critical to business success. This requires reliable service and prompt restoration after an outage or interruption. Outage management systems are mission critical when factoring in the customer element.

Using an outage management system that is integrated with a customer information system, service restoration crews can be dispatched more effectively and service restored more promptly than with a manual system. Moreover, customers can be better informed as to what's going on and when their service will be restored. Often customers are more concerned about being given an expected restoration time by the utility than they are with actually having the lights back on. Integrating an outage management system with other call-center technologies improves the knowledge base for call center agents, so they can provide information to customers with confidence.

The utility's customer-care system and interactive voice response application can also play an important role in minimizing the direct involvement of call center agents. Customers calling in are recognized by their phone number and, if the outage already is registered in the outage management, are given a voice message as to the outage's status as well as an expected restoration time. Only a small percentage of the calls require the intervention of a call-center agent. As services are restored, the system will be able to automatically call back customers to confirm that their lights are back on.

Corridor Management

Much of the application focus for GIT in utilities has occurred in the service distribution area due to the high work volumes and inherent potential savings. Another high-cost area with an opportunity for considerable benefits is the management of utility corridors such as transmission rights-of-way. This includes applications for managing vegetation, maintenance, property issues, right-of-way access, environmental protection, line clearances and encroachments.

Efficient and effective maintenance of corridors, and timely management of right-of-way related issues, are instrumental in keeping the electric system available and capable of operating at peak condition. Also, encroachments along right-of-way can become a serious safety problem if not well managed. GIS plays an important role in helping to manage these factors.

Vegetation coverage by species and "danger trees" are inventoried and used in applications that determine specific prescriptions for treatment and removal based on local climate and growth patterns. These can help determine where to plant limited-growth ground-cover species to avoid future clearance problems.

Maintenance

In addition to the management of service restoration using geospatial techniques, GIS-based IT systems can be used to support other functional areas within the utility. These include distribution design, work management and corridor management, and maintenance. Here mention should be made of inspections and maintenance. These are important not just for operational reasons, but, when considered from an IT point of view, a part of the database building process itself. It is essential that the database be updated daily. GIS-based IT can help utilities automate these routine processes, as well as record assets' current state and condition. Real-time operating decisions can be better made with the support of real-world network modeling.

Predictive Outage Management

A fully integrated GIS-based IT system provides for the geospatial linking of customer location with the circuit from which customers are served. The network model then is used to predict the probable cause of the outage, allowing efficient direction of repair crews and planning.

Integration

An integrated OMS provides both decision support tools and the integration required to make them work in the utility's environment. One underlying requirement for the design is that the components and the integration code itself should be developed with standard, published interfaces. On the one hand there is the advantage of so-called open systems, which are much less expensive to integrate, maintain, and evolve. On the other there is the attractiveness of a "one-stop" solution. The answer is in both areas, each in a different way for the three utilities depending on the evolution of their OMS. A system, such as the GE SmallWorld's Power On

System, that is open-ended, modular and compatible with many legacy systems and software from other suppliers deserves close examination.

The recommended system architecture consist of four major subsystems:

Data systems

GIS and facilities management (FM) systems

An integration framework

Activity support systems

1. Data Systems

The data systems provide additional information about the network configuration, the customers, and the health and fault status of the circuit. This status information can be thought of as instrumentation of the circuit. For example, *SCADA systems* provide remote monitoring of currents, voltages, and switch positions of various remote circuit components (direct measurements). A *trouble call system* fields customer phone calls and logs service outages (including customers complaints). A *customer information system* contains address and contact information of customers, service location, and billing information (additional information about the network and customers) that can be used in matching phone numbers of trouble calls to locations in the electrical network. Data should include circuit diagrams. Data on customers must include line section numbers and phase codes.

Data from the CIS must include the following:

- Phasing
- Transformer connection
- Line section or location
- Medical/priority information

2. Geographic Information System and Facilities Management Systems

These systems are present in the three utilities, in widely varying forms. A GIS system contains a model of the circuit topology (that is, where components are, how they are inter-connected, and some service, or customer information). Because a major goal is integration, the GIS systems must be designed to store the circuit topology information in a standard format, such as a commercially available database (SQL Server, Oracle, Sybase, or other similar database), or in files with either a published format or with standard access drivers available (OLEDB, ODBC, etc). FM systems are used to design, maintain, control, and generally manage the network. Examples of these are work order management systems (which are used to update the GIS model as the circuit is extended and maintained) and load engineering analysis packages.

Data required for the GIS is collected from multiple sources and must be keyed with the system. The most common are shown in the bulleted list that follows:

- Data types
- Meters
- Transformers
- Reclosers
- Regulators
- Switchgear
- Fusing
- Sectionalizers
- SCADA Rtu's
- IED
- Poles
- Line section data
- Load control devices
- Uninterruptible Power Supply (UPS) systems
- Solar panels
- Fuel cells

The three utilities must consider as a major priority the development of a digitized mapping system, linked to their CIS systems, that links customers with transformers.

3. Integration Framework

This framework enables data from the GIS system and the data sources to be integrated with the OMS. The integration framework can also provide integration for other decision support tools as well.

The integration framework acts as a repository for information describing all available data in the system, how they are related, and how the data consumers will use them in the system. It is *highly dependent on the data sources, their tables, fields, and keys, etc.* Note that the integration framework makes one assumption about the data sources it can communicate with. That assumption is that *the data sources are relational.*

All three utilities need to dedicate substantial resources in terms of time and personnel to ensure the timeliness, completeness, and accuracy of all data sources used by their OMS.

The OMS user must obtain trouble calls from the integration framework to update the OMS and diagnose an outage. For example, the OMS user calls an interface function of the integration engine with the identifier "GetTroubleCalls," which returns the data as a record set object. The actual query performed by the integration engine will be to join the outages table from the dispatch system, which includes crew location phone numbers, with the customers table from the CIS, which contains transformer numbers, with the transformers table in the GIS database, which contains transformer identifiers and map locations. The OMS user thus identifies the customer trouble calls in the appropriate circuit. However, the OMS is absolutely dependent on the quality of the information in the databases and digital maps.

4. Activity Support Systems

An outage is a sustained connectivity loss in the distribution network circuit. Outages may result from any of the following conditions:

- Storm, lightning, high wind, birds, and other
- Equipment failures
- Normal fault clearing action of a breaker or other protective device
- Operation of a sectionalizer device
- Planned outage
- Deliberate cutting of a line by a crew to manually isolate a fault

The OMS detects current outages, analyzes them with respect to remedial action, and initiates system restoration activities. It uses the GIS data to determine the network topology. It obtains information about the condition and status of the network from other systems, such as incoming trouble calls, voltage and current reading from the SCADA system. The results of the analysis are a determination of what faults in the distribution network equipment are causing the outages. These faults are referenced back to specific components in the GIS maps and shown to the user in a graphical user interface (GUI). The outage information can also be fed into decision support tools to help the operators analyze various courses of action for timely repair.

System Development – Criteria

Criteria to be applied for the effective development of the OMS systems at the three utilities are as follows:

- It must function well using reasonable resources (a standard PC or workstation),
- It should have the ability to detect multiple non-interacting faults within a substation circuit within reasonable response time (10s of seconds),
- It should be able to take advantage of any instrumentation available (for example, SCADA, trouble calls),
- It should provide accurate results (that is, few false alarms), and,

- It should be able to pinpoint faults at any level in the network (for example, substation, feeder, section, lateral, tap) in any type of component (for example, switch, line, transformer, fuse).

Without automation and a properly maintained GIS, the OMS will lack the ability to provide accurate and relevant results.

The Structure of Electrical Distribution Networks

A typical electrical distribution networks consists of various types of electrical components, interconnected by electrical lines. Power is input to the networks from high-voltage transmission lines at substations. Substations have several switches/circuit breakers on their outputs, which distribute power through feeder lines. Feeders lead away from the substations, and distribute power into the different service areas. Along the feeder line, there are switches that can be used to isolate parts of the circuit, but otherwise the feeders travel all the way through the service area. In some cases, the ends of feeder lines meet at switches that are nominally configured to be open, but which can be closed during outages to reconfigure the feeder circuits and temporarily restore power to areas during outages ("back-feeding"). Throughout the feeder's length are places where section lines branch off, normally connected by a switch. Attached to the section lines are lateral lines, usually with a protection device such as a fuse at the junction. Attached to the laterals are transformers, which also include protection devices and distribute power to customers through taps, or service lines. The hierarchical structure and the common use of protection devices are each of great importance to the OMS. This structure allows for the isolation of faults (assuming that they will be localized and will not cascade). This enables the OMS to reduce the task of identifying a fault to the area in which the fault originated.

Customers or loads eventually consume the power at a lower voltage. The OMS must operate within this range of lines and devices.

As the networks become more complex with more system protection and monitoring devices—especially as the recommendations in this report for capital programs are implemented—there will be further opportunities for the improvement of the OMS. But the challenges for data collection will increase geometrically. So the effectiveness of the OMS will increasingly depend on the extent to which it is automated (and the databases maintained accurately on an almost daily basis).

Instrumentation of Electrical Distribution Networks

Another unique property of electric distribution networks of the three utilities is the way in which they are instrumented.

Some have a SCADA system, which is used to remotely monitor and control substation breakers and sometimes switches in the feeder and section lines. Depending upon the amount of SCADA-enabled devices in the circuit; the voltage, current, and status measurements from the

SCADA system provide a certain level of instrumentation of the circuit. These devices tend to reside mainly in the substations and in the feeder lines.

Another more indirect, but more common, form of "instrumentation" is the observations of the customers. During outages, some customers call the utility to report the loss of power. The utilities have a trouble call system that tracks customer calls and stores the information in a database. This information can be extremely useful in evaluating problems. These calls can be considered as a sort of "instrumentation" of the circuit but with a significant difference. The "sensors" (people who report outages) are not dependable. Thus, the information provided by the TCS must be treated less as instrumentation of the circuit than as indications as to which parts of the network may be out. The trouble call data, if used as a direct indicator of which customers are out, may result in false negative readings (customers who are marked as okay, but who are actually out). If a customer does not call in, it is incorrect to assume that the power is on.

Therefore, the trouble call systems that are the backbone of the three utilities OMS must be supplemented by other sensors and instrumentation, primarily through SCADA, but importantly through a fully automated system that is capable of systemwide analysis.

Summary

As the size of the distribution system grows and the number of trouble calls increases, the automation of the OMS must increase as well. This is a challenge to the three utilities. Existing systems—that are dependent on legacy systems and localized knowledge—must be automated and integrated with GIS, CIS, and SCADA systems.

The OMS is part of a large integrated system, including GIS, TCS, CIS, and SCADA systems. These components should be maintained using a high-level GUI that requires no software engineering expertise. When properly developed, the system should be integrated and maintained by the utility experts who use it—the operators.

Recommendations

There is a strong need at the three utilities for improved technology solutions for outage and network management. Thus, this report recommends the complete automation of the entire OMS. Automation should include call taking and the customer feedback process, workflow, and reporting from the field.

For the majority of the improvements, it is recommended that "buy vs. build" is the most attractive option at the three utilities with respect to integration technology and at two of the three utilities for most subsystems.

Automation would affect the following processes as they are presently undertaken.

Current process:

- Receive trouble calls

- Predict device and location
- Work order
- Dispatch crew
- Crew arrives, investigates, and restores
- Work order completed and customer called
- Work order filed and reports generated

Limitations of current process:

- Device and location based on customer calls
- Dispatching responsible for tracking workflows
- Network tools for reconfiguration limited
- Customers are frequently uninformed, throughout process
- Feedback to system is missing
- Records and files are incomplete
- Decision making on corrective actions made in the field

Benefits of automation:

- Improved customer relations—knowledge on accepting call and feedback
- Management of the restoration process—input from systems engineers
- Crew and resource management—improved time-to-repair estimates
- Improved crew efficiency (estimated at 50%)
- Reduced outage durations (estimated 20% average time reduction)
- Up-to-date reports (helpful to planning)

Additional capabilities of automation:

- Communications using means other than telephone (for example, Internet, PDAs ["texting"])
- Proactive communications to wide customer base, not just callers
- Improved identification of failed devices
- Predictive capabilities
- Integration with remote monitoring equipment and systems (SCADA)
- Identification of high-risk outages

Automated OMS reporting objectives:

- Provide timely SAIDI

- Standard and objective criteria for measuring outages

Importance in deregulated environment:

- Performance-based rates require standardization of reporting criteria
- Standard restoration reports for duration and frequency (for example, SAIDI, SAIFI)
- Ability to affect interruption duration during the restoration process
- Objectivity–Data reports must be "cleansed" for reporting
- Regulatory agency deadlines for reporting standards (and outage report dates)

Deployment – Roadmap

The development of the automated OMS would follow the steps listed below.

- Prepare definition of outage management system
- Identify features of utility outage management system
- Identify the interface to outages – distribution system
- Identify the interface to outages - customer
- Prepare data
- Verify data quality
- Map system
- Populate Data Types
- Determine current state of CIS data
- Define current TCS
- Define current dispatch system
- Choose to rewrite existing software or outsource
- Select outage information system or virtual utility OMS
- Review available OMS technology
- Determine the state of development
- Select software vendor (could be internal supplier)
- Develop implementation plan
- Prepare budget
- Implement system
- Test system

8
POWER QUALITY

Background

The beginning of a new millennium is historically a prophetic time. As *Newsweek* magazine foretells it, within the next 100 years, we will be able to alter our genes and live to 150 years of age and beyond.

However, perhaps the most overlooked story of this new era may involve a quiet revolution that could alter the very fabric of our society worldwide. It will more than likely impact the way industries and businesses plan their operations, the way homeowners choose to build and operate their homes, and the way we all think about reliability and security. The story is one of energy. During this century, the certainty of a deregulated energy market is bringing unique business opportunities and innovative technologies to bear upon the electric industry. And, it is the service providers who understand and meet the ever-changing needs of their customers, leverage their resources, and creatively apply the latest applied technology research to their business portfolios that will have an edge up on their fierce competitors.

A technological revolution is sweeping modern society. We are at the beginning of a new era of economic and social change driven by microprocessors and the digitally based technologies that they enable. As a result, our society has become the most highly automated and interconnected in history—creating and depending on the smooth functioning of sophisticated devices and complex, interactive networks. And this revolution has just begun.

Digital technologies have a broad influence on modern society. The basic digital building blocks facilitate a wide range of applications, greatly influencing the residential, commercial, and industrial sectors. In turn, these capabilities support whole enterprises whose modern form is entirely based on digital technologies (see Figure 8-1).

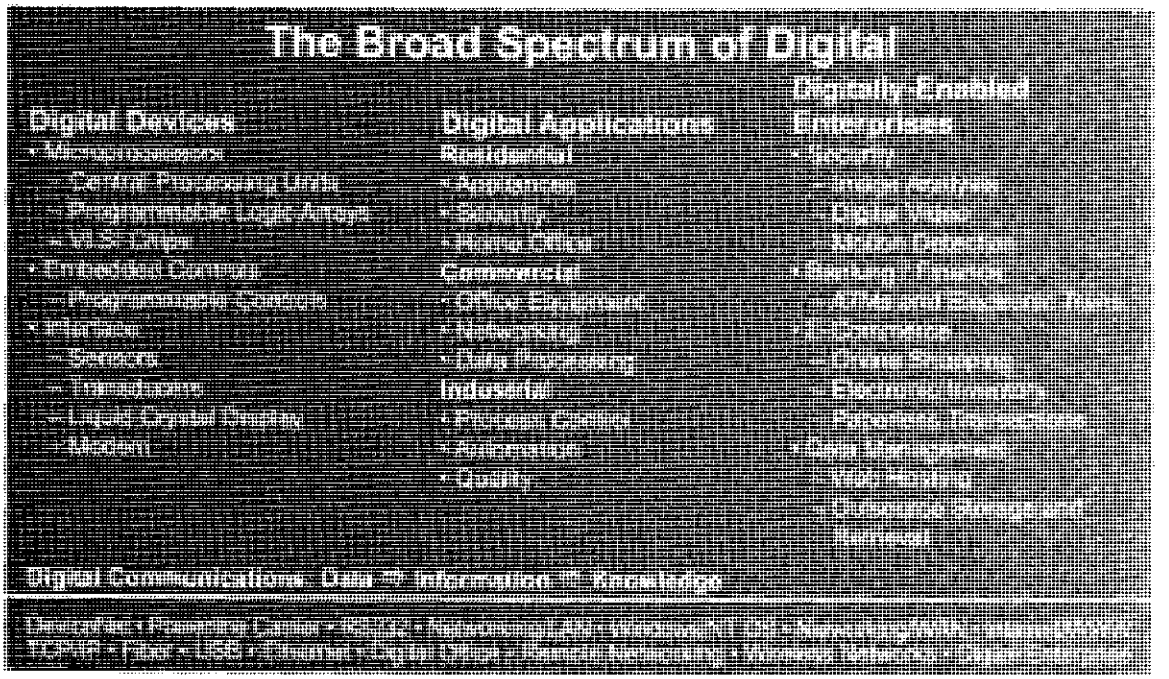


Figure 8-1
The Broad Spectrum of Digital Systems, Processes, and Enterprises

The digital revolution rides on the back of new digital technologies. These technologies, while opening whole new horizons of commerce and innovation, also have added vulnerabilities to power supply issues. Imagine that one lightning strike or power supply fault anywhere within a few hundred miles interrupts a company's processes, causing thousands of dollars in lost production and labor, equipment damage, and creation of scrap. Or imagine you're a utility engineer responsible for power quality (PQ) and reliability and, despite earnest efforts to quickly dampen or isolate the effects of that single lightning strike or isolated fault on a remote power grid, the entire distribution system sags—affecting hundreds, if not thousands, of digital systems, processes, and enterprises.

These unsettling scenarios are reality for virtually every major interconnected power grid in the world. Transmission-level problems can cause voltage disturbances—mostly sags, in which voltage on one, two, or all three phases drops below normal levels for a brief period—in distribution systems over a wide region. For example, a computer model-based study of transmission and distribution systems in the Albuquerque, New Mexico, area found that sensitive electronics there were vulnerable to transmission system faults occurring anywhere in the entire state, not just on local supply lines.[12] A study of electric supply vulnerability for a paper mill near Manchester, United Kingdom, found that the facility faced 56 significant transmission and

[12] Hingorani, N., "Introducing Custom Power," **IEEE Spectrum**, June 1995, pp. 41–48.

distribution related sags per year. Of these, 89% were caused by incidents on long 400-kilovolt transmission lines spanning many kilometers.[13]

There are clear economic and national security imperatives for the Philippines to understand the role that new digital technologies plays in modern society, and to understand the security, quality, reliability, and availability (SQRA) needs of these important technologies, particularly in the area of electric power supply. Specific capabilities are needed for electric power delivery to meet the needs of the digital society:

The Microprocessor Revolution

It is difficult to assess the true impact that microprocessors have had on our society, economy, and way of life. The sheer number of these devices already in existence and regularly entering society is already staggering, and all aspects of modern economies are affected (see Figure 1-2). Although computers are the most obvious application of microprocessors and other semiconductor chips, these comprise less than half of the applications. Consumer electronics and communications collectively use a third of semiconductor output. A large number (10%) goes to improving the productivity of industry.

[13] Bollen, M., Tayjasanant, T., and G. Yalcinkay, "Assessment of the Number of Voltage Sags Experienced by a Large Industrial Customer," **IEEE Transactions on Industry Applications**, Vol. 33, No. 6, November/December 1997, pp. 1465–1471.

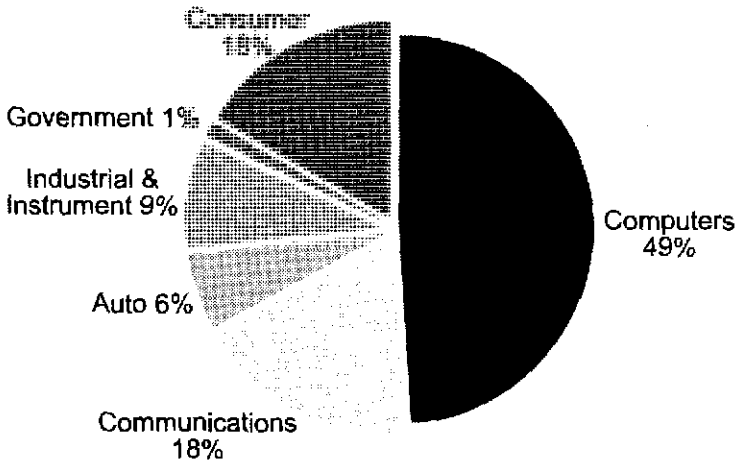


Figure 8-2
Application of Semiconductors: Percentage by End-Use Sector (Source: Semiconductor Industry Association)

The microprocessor revolution has enabled a host of innovative opportunities to improve energy efficiency, productivity, communications, and quality of manufactured goods.

With every revolution, there is a rapidly moving "cutting edge" that sweeps through society with astonishing speed, leaving some chaos in its wake. The years following these revolutions can be characterized as times of restabilization and catching up—a time when the rest of society adjusts and compensates for the changes that have unfolded. True to form, the microprocessor revolution has strained communications resources, pushed the envelope of privacy, exposed flaws in previous security practices, created an inexhaustible appetite for communications bandwidth, challenged censorship and content strictures, and spawned entirely new kinds of businesses, including co-location facilities and "mortar-less" marketplaces. The microprocessor revolution has also enabled a host of innovative opportunities to improve energy efficiency, productivity, communications, and the quality of manufactured goods (see Figure 8-3). The revolutionary aspects of microprocessors offer both enhancements as well as challenges to the economy and standard of life. Although much has been made of the amount of energy that microprocessors use, this same technology can offer energy savings opportunities that are far greater. While it is also true that microprocessors and the digital devices they enable can demand much higher performance from electrical supply systems, they also enable significant improvements in productivity.

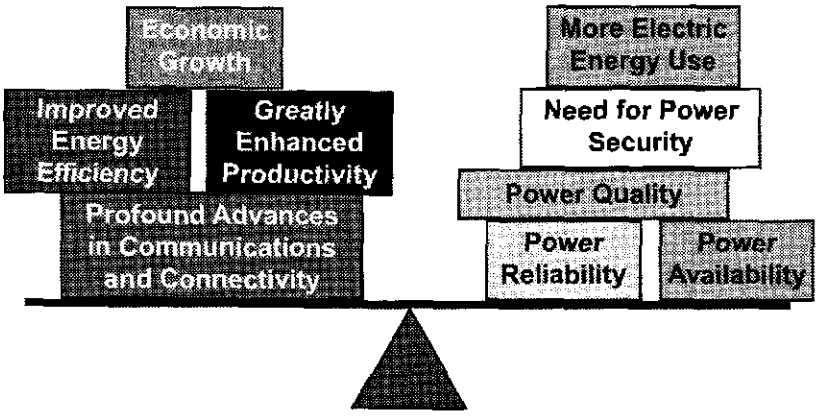


Figure 8-3
Balancing the Benefits and Costs of Microprocessor Technology

Other technology revolutions—electric power, telephone communications, rail transport, and automobiles to name but a few—have previously transformed whole societies, and the digital revolution is clearly no exception. There is an emerging digital society that has crossed over into a new era of economics and social experience, driven by digitally based technological changes that are producing new ways of working, new means and manners of communicating, new goods and services, and new forms of community. And, not surprisingly, this digital revolution is also fostering a new set of compelling challenges.

While the industrial revolution was powered primarily by steam, the digital revolution is all electric—perhaps the first substantial industry to be so. Much of the world's electrical infrastructure was designed and built in the 1930s and 1940s in an era that primarily focused on "electrification," the simple goal of making electric power available to most people and most businesses, most of the time. The electrical system is now caught in the post-revolutionary challenge of catching up to the new demands placed upon it by a 24/7 digital world. To succeed, the strategies for powering today's electrical, electronic, and digital equipment must undergo a revolution no less profound than that occurring in the digital technologies.

Relevant Codes and Standards

Many different codes and standards address PQ, safety, and operational integrity of sensitive electronic equipment. Among them, the National Electrical Code[14] (NEC) is applied most commonly. The NEC is a series of specific and detailed requirements developed by a national consensus process. Most local jurisdictions have adopted NEC requirements in part or entirely. The NEC requirements focus on safety rather than efficient equipment operation. Many new standards are being developed by different organizations (for example, Institute of Electrical and Electronics Engineers [IEEE], American National Standards Institute [ANSI], National Institute of Standards and Technology [NIST], National Fire Protection Association [NFPA], National Electrical Manufacturers Association [NEMA], and Underwriter's Laboratories [UL]) that

[14] National Fire Protection Association (NFPA), "NFPA 70 National Electric Code®," ISBN:0-87765-432-8

specifically address performance-related requirements and PQ characteristics, particularly of sensitive electronic equipment. Table 8-1 lists important standards as they relate to various PQ issues.

Table 8-1
List of Important Power Quality Standards

Power Quality Standard	Issue Covered	Comment
ANSI C62	Surge protection	ANSI C62 provides a collection of 11 guides, standards, and specifications regarding the nature of surge voltages, protective devices, device testing, and applications for surge protection.
ANSI C84.1	Voltage levels	ANSI C84.1 lists nominal voltage ratings for electric power systems and equipment (60 Hz). It also includes recommended limits for voltage imbalance on the power system.
ANSI/IEEE STD-141	Industrial powering	ANSI/IEEE STD-141 provides the latest procedures for planning the electric power distribution systems of an industrial plant. Includes new chapters on surge voltage protection, electric energy and conservation, and cost of substations and distribution systems.
ANSI/IEEE STD-142	Grounding	ANSI/IEEE STD 142 describes procedures for a thorough investigation of the problems of grounding and the methods for solving these problems.
ANSI/IEEE STD-446	Interface equipment	ANSI/IEEE STD-446 presents recommended engineering practices for the selection and application of emergency and standby power systems. Means for coping with power quality problems related to computer power supplies are also covered.
ANSI/IEEE STD-493	Reliability	ANSI/IEEE STD-493 covers industrial and commercial power system reliability.
ANSI/IEEE STD-519	Harmonics	ANSI/IEEE STD-519 provides guidance for control of harmonic current and voltage.
ANSI/IEEE STD-929	Utility interface	ANSI/IEEE STD-929 covers interconnection practices for photovoltaic power systems.
ANSI/IEEE STD-1001	Utility interface, protection, safety.	ANSI/IEEE STD-1001 presents a guide on the engineering considerations and regulation that have an impact on dispersed storage and generation (DSG) interconnections with utility systems. DSGs and utility system characteristics are described. Electrical interaction, protection, and safety are covered.

Power Quality Standard	Issue Covered	Comment
ANSI/IEEE STD-1035	Utility interface, Power factor correction, Harmonics, Frequency, electromagnetic noise	ANSI/IEEE STD-1035 recommends test procedures pertaining to utility compatibility for static power converters (one- and three-phase, 1–500 kW). Tests cover power factor and harmonics, voltage and frequency trips, time to disconnect, and conducted/radiated electromagnetic interference (EMI). This recommended practice applies to static power converters whose primary function is to deliver electric energy to the grid. Adjustable-speed drives are not covered unless they are of the regenerating type.
IEEE P-487	Life/fire safety	IEEE P487 covers wire-line communications protection in power stations.
IEEE 519	Harmonic distortion	IEEE 519 (revised) establishes goals and recommends practices for customers and utilities to control harmonic distortion levels. The new standard also outlines harmonic limitations that utilities should comply with.
IEEE P-1100	Power and grounding of sensitive electronic equipment.	IEEE P1100 covers power and grounding of sensitive electronic equipment including the grounding, powering, disturbances, interface equipment, monitoring, load susceptibility
IEEE P-1159	Disturbances, monitoring	IEEE P1159 covers monitoring (and definition) of electric power quality.
NEMA-UPS	Equipment interface	NEMA-UPS covers uninterruptible power supply specifications.
NFPA-70	Wiring, Grounding, Conductor sizing, Circuit protection	NFPA-70 (National Electric Code) provides the most widely adopted electrical safety requirements. It provides detailed descriptions of electrical wiring and grounding requirements for different types of installations. These are the minimum requirements for system grounding and do not deal with the increased requirements for noise reduction at sensitive loads.
NFPA-75	Life/fire safety	NFPA-75 covers protection of electronics, computers and data processing equipment.
NFPA-78	Surge protection	NFPA-78 covers lightning protection for automated data processing (ADP) installations.
NIST FIPS-94	Grounding, disturbances, life/fire safety, telecommunications, noise control	NIST FIPS-94 describes techniques for resolving typical power and grounding problems frequently encountered with large- and medium-scale ADP installations. These include grounding, power conditioning, life safety, control of static electricity,

Power Quality Standard	Issue Covered	Comment
		and lightning protection.
NIST-SP768	Disturbances	NIST-SP768 provides information on power quality covering issues regarding impact on sensitive electronic equipment problems and solutions.
UL 1449	Surge protection	UL 1449 contains basic requirements for products covered by Underwriter's Laboratories, Inc. Requirements cover surge-suppression products designed for repeated limiting of transient voltage surges on 50- or 60-Hz power circuits.

Why Investigate Power Quality

Across the world, electric utilities operate power generation, transmission, and distribution systems to provide reliable electric power to homes, factories, and businesses. Customers who rely on these utilities expect not only constant frequency (50 Hz or 60 Hz) AC electric service, but also "disturbance-free" power—power free from transients, sags, and swells that may disrupt equipment operation. Figure 8-4 shows a disturbance-free sine wave.

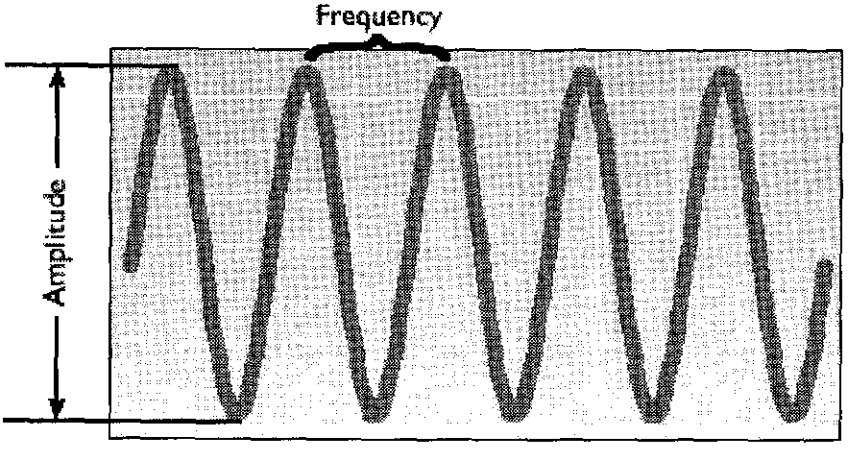


Figure 8-4
Clean (Disturbance-Free) Sine Wave

The equipment being connected to the power system today is more sensitive to electrical disturbances than ever. Microprocessor-based hardware, small relays, and switch-mode power supplies can shut down during voltage sags that would have gone unnoticed a few decades ago.

Today's equipment may also produce undesirable emissions. For example, most electronic equipment draws current in pulses, as opposed to drawing current in concert with the applied voltage. The resulting distortion of the power-system sine wave, called harmonic distortion, can

cause conductors in the power system to overheat. In addition, the operation of power-factor-correction capacitors can magnify harmonic distortion to unacceptable levels. Equipment sensitivity, equipment emissions, and equipment interaction with the power system combine to pose an enormous challenge to today's energy providers. Understanding PQ is the first step in meeting that challenge. What follows is a basic description of PQ and the PQ audit, including a brief overview of the many types of power disturbances.

Power Quality Fundamentals

Categories of Power Disturbances

Power disturbances can originate from many sources: severe weather, accidents involving distribution lines, lightning, or customer loads. Electricity users are frequently the source of their own power disturbances. Local loads can cause interference with their own electric systems or disturb a neighboring operation. Categories of power disturbances were developed to help solve PQ problems. It's important to be able to classify power disturbances for analysis purposes. To describe power disturbances, the power community has adopted the categories in Table 8-2, as defined by Std IEEE 1159-1995. The table also illustrates certain power variations.

Table 8-2
Summary of Power Disturbances and Characteristics as Defined by IEEE Std. 1159-1995

Categories			Typical Duration	Typical Spectral Content	Typical Magnitude	Characterizing Method	Typical Causes	Examples of Power Conditioning Solutions
Transients	Impulsive	Nanosecond	> 50 nanoseconds	5 ns rise		Peak Magnitude, Rise Time, Duration	Lightning, Electro-Static Discharge, Load Switching, Capacitor Switching	Surge arrestors, Filters, Isolation Transformers
		Microsecond	50 nanoseconds to 1 millisecond	1 micro-sec. rise				
		Millisecond	> 1 millisecond	0.1 ms rise				
	Oscillatory	Low Frequency	0.3 millisecond to 50 milliseconds	< 5 kHz	0 to 4 pu	Waveforms, Peak Magnitude, Frequency Components	Line/Cable Switching, Capacitor Switching, Load Switching	Surge arrestors, Filters, Isolation Transformers
		Medium Frequency	> 50 milliseconds to 5 microseconds	5 to 500 kHz	0 to 8 pu			
		High Frequency	> 5 microseconds	0.5 to 5 MHz	0 to 4 pu			
Short Duration Variations	Sag		*Instantaneous 0.5 cycles to 30 cycles *Momentary 30 cycles to 3 seconds *Temporary 3 seconds to 1 minute		0.1 to 0.9 pu	RMS vrs. Time, Magnitude, Duration	Remote System Faults	Ferroresonant Transformers, Energy Storage Technologies, UPS
	Swell				1.1 to 1.8 pu			
	Interruption				< 0.1 pu	Duration	System Protection (Breakers, Fuses), Maintenance	Energy Storage Technologies, UPS, Backup Generators
Long Duration Variations	Undervoltage		> 1 minute		0.08 to 0.9 pu	RMS vrs. Time, Statistics	Motor Starting, Load Variations, Load Dropping	Voltage Regulators, Ferroresonant Transformers
	Overvoltage				1.1 to 1.2 pu			
Voltage Unbalance			steady state		0.5 to 2%			
Waveform Distortion	DC Offset		steady state		0 to 0.1%			
	Harmonics			0 to 100th Harmonic	0 to 20%	Harmonic Spectrum, Total Harm. Distortion, Statistics	Nonlinear Loads, System Resonance	Filters (active or passive), Transformers (cancellation of zero sequence components)
	Interharmonics			0 to 6 kHz	0 to 2%			
	Notching							
	Noise			broad-band	0 to 1%			
Voltage Fluctuations			Intermittent	< 25 Hz	0.1 to 7%			
Power Frequency Variations			> 10 seconds			Variation Magnitude, Frequency of Occurance	Intermittant Loads, Motor Starting, Arc Furnaces	Static Var Systems

Transients can be classified into two categories—impulsive and oscillatory. The current and voltage waveform defines the transient category.

Impulsive Transients are sudden sub-cycle changes in the steady-state condition of voltage, current, or both. They are unidirectional in polarity while transitioning in either positive or negative direction. The most common causes of impulsive transients are lightning strikes.

Oscillatory Transients are instantaneous, rapid changes of polarity in voltage or current. Oscillatory transients with the primary frequency greater than 500 kHz and a typical duration of several cycles of the fundamental frequency are considered *high-frequency transients*. High-frequency oscillatory transients are system load and switching variations. Long-duration variations can be either overvoltages or undervoltages. However, overvoltages and undervoltages are generally not the cause of system faults.

Overvoltages can be a result of switching off large loads or switching on capacitor banks. Incorrect tap settings on transformers can also result in system over voltages.

Undervoltages are defined as a decrease in power voltage ranging from 0.8 to 0.9 per-unit (pu) for the duration of greater than 1 minute. Undervoltages result from switching on of loads or switching off of capacitor banks.

Sustained Interruptions are the decrease of supply voltage to zero for a period greater than 1 minute. Voltage interruptions longer than 1 minute are often permanent and require manual intervention for restoration.

Voltage Unbalance, or imbalance, is defined as the ratio of the negative or zero sequence component of the steady state voltage the respective positive sequence component. Unbalance can be estimated as the maximum deviation from the average of the three-phase voltages divided by the average of the three-phase voltages, expressed in percent. The primary source of voltage unbalance less than 2 percent is unbalanced single-phase loads on a three-phase circuit. Voltage unbalances can also be the result of capacitor bank anomalies, such as blown fuses on a three-phase capacitor bank.

Waveform Distortion is a steady-state deviation from an ideal sine wave of fundamental power frequency characterized by the spectral content of the deviation. The five primary types of waveform distortion are:

- DC offset
- Harmonics
- Interharmonics
- Notching
- Noise

DC offset is the presence of DC voltage or current in an AC power system. Direct current in an AC network can be detrimental to equipment because of an increase in transformer saturation, additional stressing of insulation, and other adverse effects.

Harmonics are sinusoidal voltages or currents having frequencies that are integer multiples of the fundamental power frequency. Harmonic distortion exists because of nonlinear devices and loads in the power system. Harmonic distortion levels can be characterized by the harmonic spectrum with magnitudes and phase angles of each individual harmonic component. Total harmonic distortion (THD) is a quantity commonly used to measure harmonic distortion.

Interharmonics can be found in networks of all voltage levels. They can appear as discrete frequencies or as wide-band spectrum. The main sources of interharmonics are static frequency converters, cyclo-converters, induction motors, and arcing devices. Effects of interharmonics are not well known, but have been known to affect power line signaling and to induce visual flicker on devices such as CRTs.

Notching is a periodic voltage disturbance caused by normal operation of power electronic devices when current is commutated from one phase to another. During this period, there is a momentary short circuit between the two phases. The severity of the notch at any point in the system is determined by the source inductance and the isolating inductance between the converter and the point being monitored.

Noise is electrical signals with broadband spectral content less than 200 kHz superimposed upon the power system voltage or current in phase conductors, or found in neutral or signal conductors. A typical magnitude of noise is less than 1 percent of the voltage magnitude. Noise can be caused by power electronic devices, control circuits, arcing equipment, loads with solid-state rectifiers, and switching power supplies. Using filters, isolation transformers, and some line conditioners can mitigate the problem.

Voltage Fluctuations are systematic variations of the voltage envelope or a series of random voltage changes. Any load with significant current variations, especially reactive, can cause voltage fluctuations. Voltage fluctuations can cause lights to flicker. Voltage fluctuation magnitudes as low as 0.5 percent from nominal can cause lamp flicker at frequencies within the range of human perception.

Power Frequency Variations are created by fluctuations in the rotational speed of the generators. Depending on generation capacity, generator speed (and therefore frequency) may be affected by changes in system loading. A sudden increase in load such as a transmission system fault, large load blocks being disconnected, or a generation source being taken off line, can cause power frequency variations.

Power Quality Investigations

Most PQ investigations require a combination of measurements and analyses. Measurements are critical for identifying the characteristics of the PQ concern. They provide the base information that can then be used to perform further analysis and evaluate possible solutions to problems. Before performing either measurements or simulations, it is important to perform a site survey to evaluate wiring and grounding, identify sensitive equipment, and obtain the history of the PQ concern. Even before performing the site survey, it is important to get all interested parties together to go over the PQ concerns involved. A systematic approach to diagnosing and solving a

power-related equipment problem is best. It takes into account distribution system interactions, premises wiring, and various mitigation measures aimed at reducing the interference or its effects, regardless of the source. The flowchart shown in Figure 8-5 can be used as a guide in taking a systems approach to determining power-conditioning needs.

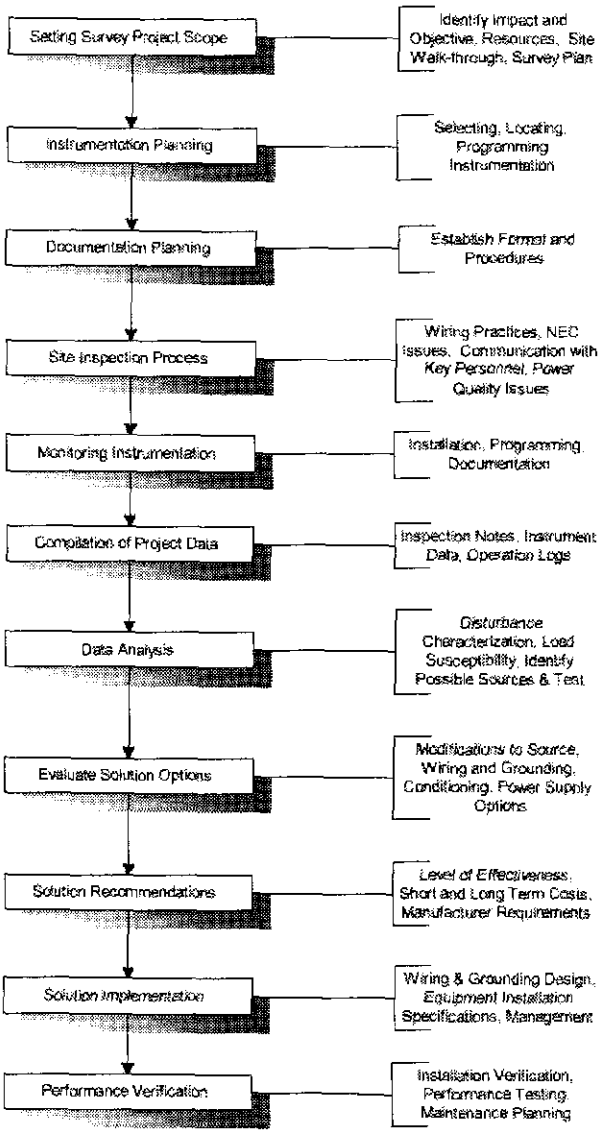


Figure 8-5
Flowchart for Performing Power Quality Investigations

Solving Power Quality Problems – Start With the Basics of Wiring and Grounding

Market studies indicate that consumers in the U.S. are spending more than $5 billion on PQ today and the compound annual growth rate (CAGR) of spending is estimated at a conservative

rate of 8% up to a more optimistic rate of 16%. So, based on the inherent sensitivities and associated downtime costs of microprocessor-based technologies and the growing power-conditioning market, PQ is a growing business.

But with all this attention and dollars being poured into PQ, how does wiring and grounding fit into the picture? Facility wiring and grounding can and does affect PQ. In fact, wiring and grounding is considered the cornerstone or foundation upon which equipment of any type will function—either in an unsafe and poor performance manner or in a safe, reliable and improved performance manner. EPRI and other studies indicate that as many as 70% of all electronic equipment failures attributed to PQ may result from inadequate wiring or grounding, or interactions with other electrical loads. Therefore, before considering a purchase of power-conditioning equipment, commercial and industrial customers should check their own facilities carefully to determine the causes of electronic malfunctions. Sometimes, the solution to a PQ problem is simply to tighten a loose connection or replace a corroded conductor.

Although the wiring and distribution equipment and installation must meet all local building code requirements, most local codes currently do not address PQ and performance issues. In the United States, most local codes are based on recommendations outlined in the NFPA 70 National Electrical Code (NEC). The NEC states within its purpose:

> "The purpose of this Code is the practical safeguarding of persons and property from hazards arising from the use of electricity...but not necessarily efficient, convenient, or adequate for good service or future expansion of electrical use."

While the NEC's primary goal is for personnel and equipment safety, many practices and techniques recommended by the NEC can increase performance while maintaining a safe electrical system. Once wiring and grounding have been verified to be in compliance and performance is still not adequate, power conditioning should be considered to enhance performance.

Levels of Power Conditioning

Power conditioning can be applied at several different levels, each of which has its own life cycle cost advantages and disadvantages. Graphically, this is shown in Figure 8-6.

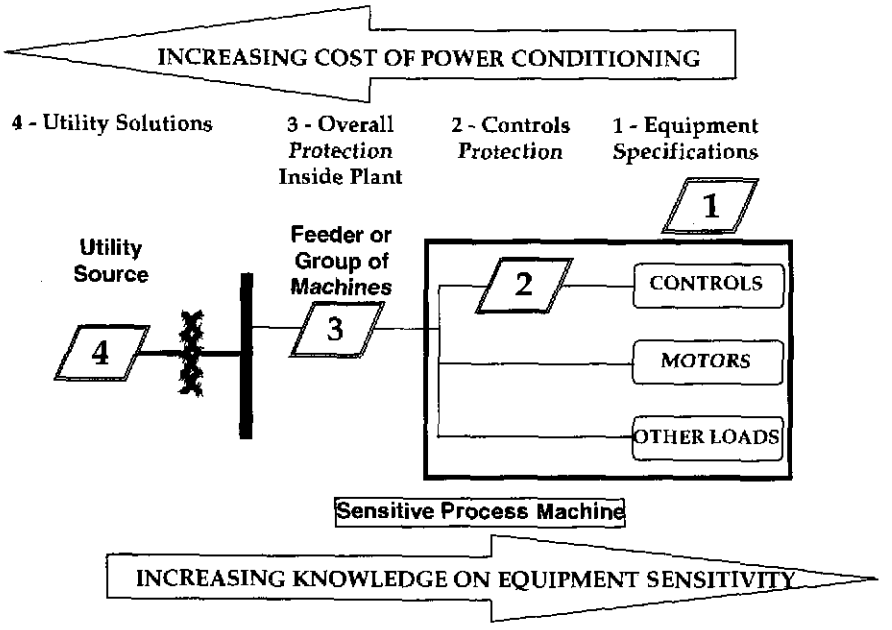


Figure 8-6
Power Conditioning Cost Versus Knowledge

As the power-conditioning technology is moved from inside the facility toward the service entrance, the cost increases. In contrast, to move the point of application farther inside the plant, more knowledge of the process equipment is necessary. As an example, if one knows nothing about the particulars of the process equipment, but has unlimited budget, then power conditioning can be approached at the utility level with very large-scale devices or expensive system modifications. On the other hand, if one has the time to invest in evaluating the performance of the equipment inside the facility, then the solution may be applied at a lower voltage level and at smaller subcomponents of the process. This would lead to significant equipment cost savings.

Naturally, the least expensive option for process ride-through is to include the ride-through requirements in the specifications for the equipment. This is point 1 in Figure 1-6. If ride-through standards exist, this merely requires that the specification list the standard to be met. Unfortunately, most industries do not have such standards in place.

At point 2, the system must be studied; but there is usually some correlation between process shutdown and the control circuits used in the system. Therefore, power conditioning can be applied to the control circuit or control devices responsible for shutdown of the system. While this may not remove all the sensitivity of the system to voltage variations, it will, in all likelihood, take care of 80 percent of that sensitivity. At this level, the power conditioners are the least costly on the market.

Point 3 is at the panel level feeding the process line or lines. At this level, the power-conditioning devices must be larger scale, on the order of tens to hundreds of kW. They will also carry a higher price. In this case, the knowledge of the process equipment is not required in as much detail, and the improvement in system performance may be even better than the 80 percent

mentioned previously. The drawback is that power conditioning may be applied for loads that do not actually need it. In addition, some engineering will be necessary to install such a device, which increases the final cost.

Point 4 is at the service entrance to the plant where the power conditioning device(s) must support the entire plant load. This could be anywhere from 1 to 50 MW. As such, this is the most costly approach. Hopefully, the technology chosen for this level is such that 100 percent of the process sensitivity is removed. However, as is true at point 3, it is possible that the majority of equipment protected does not require protection.

Power-Conditioning Technologies

Listed below are mitigation tools used to accomplish effective power conditioning. Each type of system is discussed in the following sections.

- Motor-generator sets
- Power-conditioning flywheels
- Uninterruptible power supplies (UPSs)
- Batteryless ride-through devices (BRTDs)
- Power-conditioning ultra capacitors
- Constant-voltage transformers (CVTs)
- Magnetic synthesizers
- Isolation transformers
- AC line reactors
- Transfer switch
- Harmonic filters
- Transient voltage surge suppressors (TVSS)

Motor-Generator Sets

A motor-generator set (MG set) is an effective tool for isolating electrical systems. Comprised of an electric motor that drives an electric generator, an MG set transforms incoming electrical power into mechanical energy, which is then used to drive a generator, converting the energy into electricity once more. The only connection between the two electrical systems is the mechanical connection of the MG set. Because of this electrical isolation, MG sets are effective at preventing the transmission of transients, harmonics, and electrical noise from one system to another. Because voltage is determined by rotor speed, the inertia of the rotating equipment (rotors and connecting shafts) can help equipment ride through short-duration voltage sags or interruptions. Inertia added to the shaft, in the form of a flywheel, can increase the ride-through duration. MG sets can also be used to change system frequencies and voltages. A relatively new

class of MG sets is the Written-Pole™ Roesel Motor-Generator (RMG). The RMG uses Written-Pole™ technology to change or "write" poles onto the stator, ensuring constant frequency and voltage from the generator for as long as possible.

Power-Conditioning Flywheels

Flywheels are one of the oldest and most common mechanical devices in existence. Kinetic energy is stored in a rotating mass (the flywheel), and this energy is drawn upon when needed to smooth the operation of the machine. A flywheel, in essence, is a mechanical battery that stores kinetic energy. However, until recently, flywheels were only useful for short ride-through or output modulation on mechanical devices. Modern power electronics, bearing, and composite technologies are making flywheels a viable way to ride through and smooth out PQ events.

Flywheels are available in many sizes, from less than 100 kW to several megawatts. As a straightforward energy-storage device, flywheels are used to replace or augment conventional batteries in supporting a critical DC bus, such as the DC link of a UPS, an adjustable-speed drive (ASD), or a stand-alone power unit (such as those commonly used in telecommunications). Flywheels can also be used to directly support a load at line frequency, although this requires the addition of some line frequency system components such as static switches, boost transformers, or output inverters. Frequent cycling of flywheel systems does not appreciably diminish useful life. Flywheels are relatively unaffected by ambient temperature extremes. The rate at which energy can be exchanged into or out of the flywheel is limited only by the motor-generator and power electronics design. Therefore, it is possible to withdraw large amounts of energy in a far shorter time than with traditional chemical batteries. Environmental issues present with batteries are not present with flywheel systems.

Uninterruptible Power Supply (UPS)

Uninterruptible power supplies have long been used to protect mission-critical equipment from the effects of temporary power interruptions and other PQ variations. The UPS comes in a wide array of sizes ranging from just a few hundred VA to as large as one megawatt. The protection capabilities and performance features also vary from model to model, depending on the technology used. The four basic categories used to describe UPS products include on-line UPS, standby UPS, line-interactive UPS, and rotary UPS.

On-Line Uninterruptible Power Supply

The on-line UPS (also called rectifier/charger or double conversion) takes the AC input power, rectifies it, and converts it to a DC voltage. The DC is then fed into an inverter and filtered to recreate AC power for the output loads (see Figure 8-7). As with the rotary UPS system, the on-line UPS creates a separately derived source as defined and recommended by the NEC. Advantages of this type of system include isolation between the loads and the normal power source, very good power-conditioning capability, and no break in output power when transferring the loads to and from battery backup. Disadvantages include lower energy efficiencies than other similarly sized units, limited starting-current availability for connected

loads, creation of input harmonic current distortion (unless the unit has a power-factor-corrected input), and higher cost than similarly sized standby units.

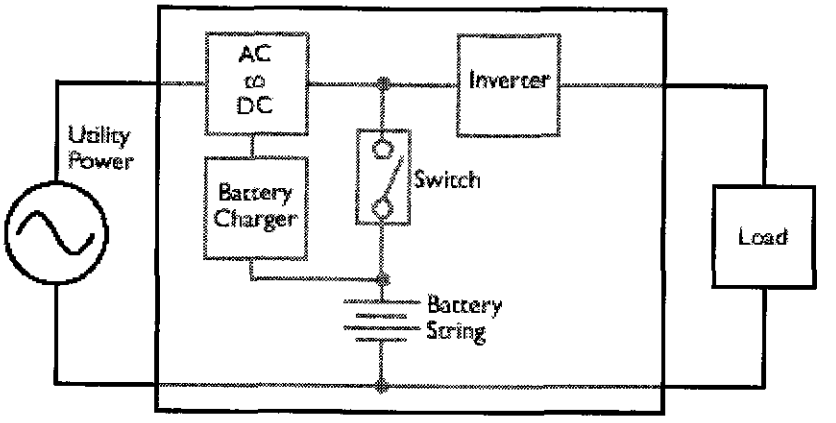


Figure 8-7
Configuration of an On-Line Uninterruptible Power Supply

Standby Uninterruptible Power Supply

This type of UPS is typically the least expensive and, depending on the manufacturer, may also be referred to as either a UPS or a standby UPS. A large percentage of these units are used in 1-kVA or less applications supporting PC power supply and peripheral loads. A standby UPS is intended for loads that can tolerate a momentary loss of power during the transfer to and from battery. The unit allows the load to operate on normal AC line voltage as long as the line voltage stays within a predetermined window. If the voltage goes outside this window, the unit transfers the load to battery power (see Figure 8-8). Advantages of this type of power system include low cost, high efficiencies (typically 95 to 99 percent), and the ability to support high load inrush currents. Disadvantages include limited power-conditioning ability and no isolation between the load and the normal power source.

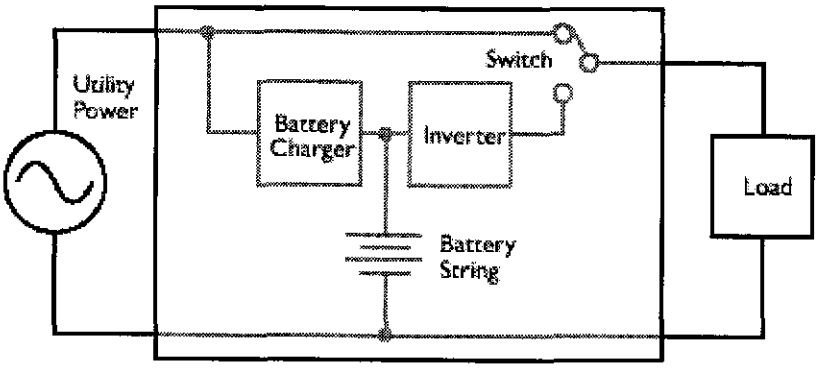


Figure 8-8
Configuration of Standby Uninterruptible Power Supply

Rotary Uninterruptible Power Supply

Rotary UPS systems have gained in popularity because of the availability of ratings up to 10,000 kVA. This type of UPS system is typically very reliable because of the low parts count. During normal operation, an AC motor turns an AC generator, while the battery bank is charged by a DC generator. During a power failure, a DC motor turns an AC generator, using battery power. The transition to and from battery power is accomplished by motor controls with no contactors or switches so that the AC generator output is totally uninterrupted. This type of design completely eliminates the rectifier/charger, inverter, and static bypass switch of conventional UPSs. Other rotary UPS systems may employ power electronics for the battery backup portion of the system.

Batteryless Ride-Through Devices

Protection from momentary voltage sags and interruptions is a critical feature for process and stand-alone equipment. Whether the application is a 100-megawatt industrial plant or an individual electronic device such as a relay, reliability depends on the equipment's ability to withstand momentary voltage variations. A variety of ride-through devices have become available recently, serving to reduce the impact of momentary voltage variations and, in some cases, very short-term interruptions.

Batteryless ride-through devices (BRTDs) come in a variety of configurations that make use of the full range of power electronics technology. Magnetic components such as transformers and inductors, as well as electronic devices such as diodes, power switches, and capacitors, are used to control and shape electrical energy into a form that improves the ability of the load to tolerate variations in utility power. The major categories of BRTDs are AC ride-through and DC ride-through. Many different types of energy-storage options are available for BRTDs. For example, flywheel, fuel cell, and super capacitors are just a few of the many available alternative sources of energy that may be found in BRTDs Each alternative source has its relative merits, which generally depend on specific application issues such as size, cost, and availability, but also depends on the progress of technical advancement. As these technologies mature, they may become more popular.

Power-Conditioning Ultra Capacitors

Sometimes referred to as super capacitors, ultra capacitors are capacitors with exotic combinations of dielectrics and electrodes, such as carbon composite electrodes and organic electrolytes. Ultra capacitors can store several hundred times as much energy (on a weight and volume basis) as conventional capacitors and can still deliver that energy at high discharge rates. Present day designs have power densities of 2000 to 4000 watts per kilogram of material and specific energy of 5 to 10 W/kg. Capacitor systems have high cycle lifetimes, typically in excess of 500,000 discharge cycles. Individual capacitor voltages are low, typically less than 3 volts, requiring many series-connected units for large power requirements. Each capacitor may store from 1000 to 2700 farads of charge. With the energy is stored as a voltage, the voltage varies in direct proportion to the state of charge. Electronics may be provided to accommodate wide

output voltage range as energy is extracted, or these electronics may be avoided, limiting the discharge of the capacitor to a smaller percentage of the available energy. Because of their relatively high power density and high cycle life, ultra capacitors are a good choice to provide fast ride-through of short PQ events. Ultra capacitors are primarily used as part of a larger system to provide support for the critical DC bus applications such as UPSs, ASDs, DC systems, or telecommunications equipment. When used in conjunction with batteries in a UPS system, ultra capacitors can extend the useful life of the batteries by providing power through short events and decreasing the number of discharge cycles experienced by batteries. Ultra capacitors can also accept and store large power surges from regenerative braking. Therefore, they can be especially useful in ASD applications where regenerative braking is common.

Constant-Voltage Transformers

The constant-voltage transformer (CVT) is a popular power conditioner for mitigating the effects of voltage sags on industrial and commercial equipment. A CVT uses a ferro-resonant transformer to maintain relatively constant output voltage, despite brief variations in input voltage. CVTs are excellent solutions for momentary voltage sags to approximately 50% of nominal voltage. The CVT's load-support characteristics include:

- Operates in a saturation mode, providing excellent output voltage regulation for connected loads.
- Provides an outstanding solution for voltage sags but not a solution for momentary interruptions.
- Should be sized at least twice as large as the load VA requirement and at least two times the peak inrush demand of the load or loads.

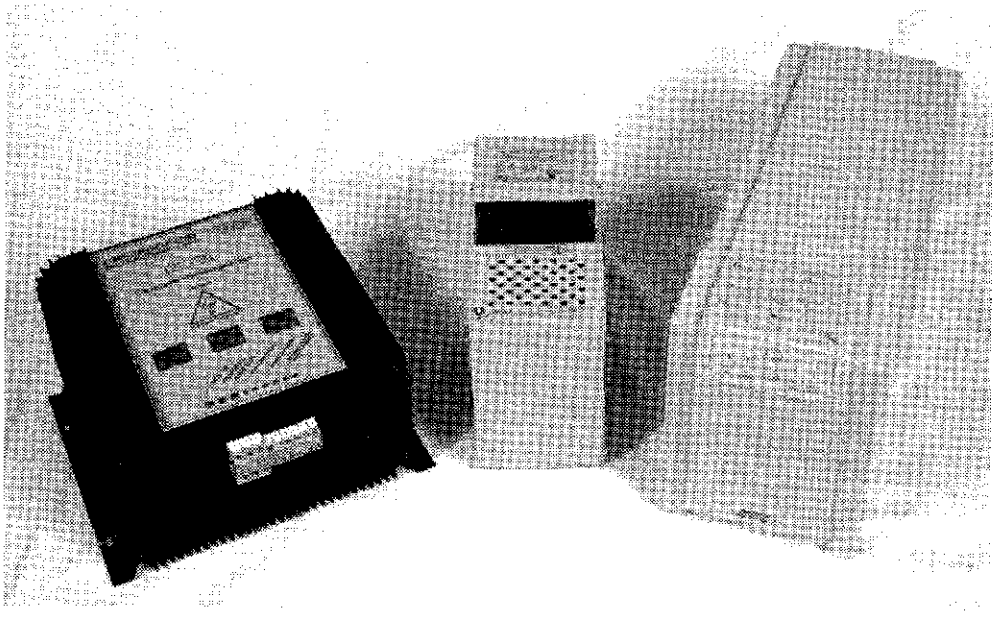


Figure 8-10
Batteryless Ride-Through Device (BRTD) (On the Left), Constant Voltage Transformer (CVT) (In the Middle), Uninterruptible Power Supply (UPS) (To the Right)

Magnetic Synthesizers

Magnetic synthesizers are the equivalent of constant-voltage transformers for three-phase loads. They are more efficient and available up to much higher power ratings (such as 200 kVA). They are used for large computers and other electronic equipment that is sensitive to voltage variations. These are ideal for situations where interruptions are very rare but where ride-through support against voltage sag is needed.

Isolation Transformers

The simple isolation transformer can protect against many high-frequency transients and can prevent nuisance tripping attributable to capacitor switching on the utility side. These transformers are used to attenuate noise and transients as they pass from winding to winding by providing a zero-volt reference for the system. This is accomplished with three different techniques:

- Common-mode rejection.
- Electrostatic shielding
- Additional impedance

Active Power Line Conditioner

Active power line conditioners (APLC) can involve series- and/or shunt-connected power electronics to condition the voltages and currents supplied to sensitive and distorting loads. Power levels available are continually increasing, and designs for application on higher-voltage systems are becoming available. Series-connected active conditioners can provide voltage regulation and correct for harmonic components in the voltage. The controls can be designed so that the series-connected unit looks like a very high impedance to harmonic components, improving the performance of passive filters (hybrid configuration). Parallel-connected active conditioners are primarily designed to compensate for harmonic components and reactive power from disturbing loads.

AC Line Reactors

AC line reactors are commonly used with adjustable-speed drives to reduce current harmonics, increase power factor, reduce current unbalance, and minimize nuisance trips caused by capacitor-switching transients. The AC line reactor may also be used to minimize the impact of long-lead transient voltages on the output side of an adjustable-speed drive.

Power-Conditioning Static Transfer Switch

For continuous industrial processes, the use of power conditioning on individual process elements is not always cost effective. Often, power-conditioning solutions require many devices, such as UPSs and CVTs, which have installation and maintenance concerns. An alternative is a centralized approach—the static transfer switch (STS). The STS selects between two or more sources of power and allows the "best" of the sources to supply the electrical load. The basis for the STS is similar to that of the electromechanical switch, which transfers a load from one power source to the other. The significant advantage of the STS is that it can transfer the load much faster than the electromechanical switch, thus resulting in the load being protected against disturbances by an almost seamless transfer from a preferred power source to an alternate power source. In addition to being faster than the electro-mechanical switch, the performance of the STS is not degraded as a result of repeated transfers.

Harmonic Filters

Nonlinear loads such as arc furnaces, ASDs, battery chargers, computers, UPSs, and welders can cause harmonic distortion of the supply, both voltage and current. If the harmonic content of the supply exceeds a certain level, harmonics can cause overheating in wires and equipment and the malfunction of sensitive loads. When harmonics become a problem, there are several options available to the user. The first option, of course, is to replace the equipment that is generating the harmonics with "cleaner" equipment. However, this option is often extremely expensive, or completely impossible, so the next available option is to eliminate the harmonics with an additional piece of equipment. Line reactors and other similar devices can help to attenuate and minimize the harmonics generated by a particular piece of equipment; but to fully eliminate

harmonics, a more drastic solution is necessary. Two types of harmonic filters can do the job: active and passive.

Active Harmonic Filters

Active harmonic filters are a power-electronics solution to harmonic disturbances, and can be used to mitigate both voltage and current harmonics, depending on the design. Operating on a principle of harmonic cancellation, an active filter uses power electronics to inject currents (or voltages) into the supply, which cancel problem harmonics. To determine what waveforms are necessary to mitigate a disturbance, active filters monitor the supply. The speed of modern power electronics and digital signal processors enable the filters to quickly adjust to changing conditions. Active filters typically resemble adjustable-speed drives in components and construction, with a capacitive DC link feeding a power electronic inverter. This inverter is used to inject power into the load. Because of the dynamic nature and fast switching of the power electronics, several harmonic orders can be cancelled, and the same device can compensate reactive power. Active filters are typically connected parallel to the supply of a nonlinear load, allowing the injection of currents when necessary.

Passive Harmonic Filters

Passive harmonic filters are used in some instances to attenuate the magnitude of particular harmonic currents. The passive harmonic filter consists of a capacitor and inductor in series, which are tuned to resonate at or below one harmonic order. This effectively traps harmonic currents in the L/C circuit. Each tuned filter or trap is designed to deal with one fundamental harmonic order. Usually, multiple filters are needed to fully address harmonic distortion, each tuned to deal with a specific harmonic (5th and 7th are the most common). Because tuned harmonic filters change the system dynamics, they must be specifically designed to work with other filters and the power system to which they are applied. Properly designed, a passive harmonic filter can be used to eliminate harmonic distortion present on the electrical network, as well as those harmonics generated by a problem load. If improperly applied, however, parallel resonance can occur near the combined system harmonic frequency, exacerbating an existing problem. Because of these complex interrelations, the design and tuning of a passive harmonic filter is a task suitable only for PQ experts; therefore, passive harmonic filters should only be applied after careful and deliberate consideration of all possible harmonic loading issues.

Transient Voltage Surge Suppressors

Sensitive electronic equipment has come into widespread use in residential, commercial, and industrial facilities. Most of this equipment can benefit from supplemental protection against damaging transients caused by lightning and/or load switching. The transient voltage surge suppressor (TVSS), also commonly referred to as a surge-protective device (SPD), is a popular choice to protect electronic equipment from potentially disruptive or destructive power disturbances. TVSS devices come in a variety of configurations, and their use depends on the type of installation. For example, to provide 100% protection from transient voltages, a coordinated system of surge suppression is required throughout a facility. A high-energy

suppressor should be located at the service entrance (see Figure 8-11) to protect against lightning-related surges. A suppressor should be located at surge-generating loads within a facility and at sensitive loads. Finally, data-line, modem, and Cable-Access Television (CATV) suppressors should be applied to data and communication wiring. TVSS devices can be broken into three categories that are based on the type of port protected:

- Power-line surge protectors
- Data-line surge protectors
- CATV and modem-port surge protectors.

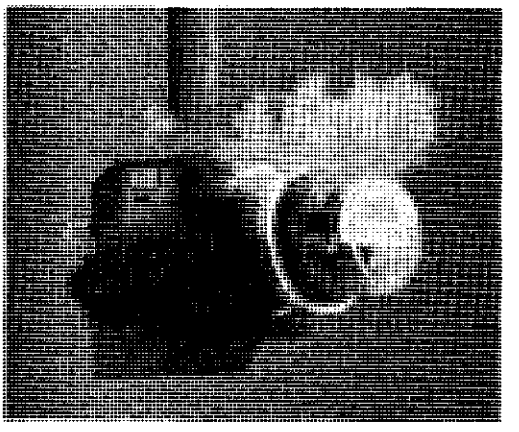


Figure 8-11
Meter Socket Surge Protection Device

Custom Power Solutions

A custom power solution is the use of power electronic or static controllers in distribution systems rated at 1 kV through 38 kV for the purpose of supplying a level of reliability and/or PQ that is needed by electric power customers who are sensitive to power variations. Custom power devices, or controllers, include static switches, inverters, converters, injection transformers, master-control modules, and/or energy-storage modules that have the ability to perform current-interruption and voltage-regulation functions in a distribution system. A custom power device is a type of power-conditioning device. Power-conditioning technology, in general, includes all devices used to correct the problems faced by end-user loads in response to voltage sags, voltage interruptions, voltage flicker, harmonic distortion, and voltage-regulation problems. While the term *power conditioning* has no voltage boundary, the term *custom power* is bound by the scope of IEEE P1409 to include power conditioners with input and/or output voltage ratings between 1 and 38 kV. This scope limits the location of a custom power device to a medium-voltage primary distribution system. However, the technologies used at medium voltage and low voltage are frequently very similar.

Table 8-3
Application Matrix for Custom Power Device

	Static VAR Compensation	Static Shunt Compensation	Source Transfer Switch	Static Series Compensator	Static Voltage Regulator	Backup Energy Supply Device
Voltage sag	√[1]	√[3]	√	√[5]	√	√
Voltage swell	√	√	√	√	√	√
Momentary interruption			√			√
Capacitor-switching transient	√	√		√	√	
Voltage regulation	√	√	√	√	√	
Flicker	√	√				
Harmonics	√[2]	√[4]				
Reactive power compensation	√	√				
Cost Range (USD = $US)	50-200 USD/kvar	120-75 USD/kvar	500-1000 USD/amp	150-250 USD/kVA	80-125 USD/kVA	750-1500 USD/kVA

[1]Generally corrects up to 100% of nominal for a sag to 65%-70% of nominal. Corrects up to 90% of nominal for a sag to 55%-60%.

[2]One model corrects 5th and 7th. Other two models have de-tuning filters provided for harmonics determined to be present.

[3]Generally corrects up to between 90% and 100% for a sag to 20% of nominal.

[4]One model corrects 25th harmonic, the other corrects to the 17th.

[5]One device corrects for voltage sags to 0%. Others typically correct for voltage sags down to 50%.

Evaluations of Capacitor-Switching Transient

Capacitor switching is a common event on the power system. Capacitor-energizing operations result in transient voltages. These voltages are generally not a problem for power system equipment, but they can impact end-users in some circumstances. Surge protection in the end-user facility designed for high-frequency transients may not be able to handle the energy associated with the lower frequency capacitor-switching transients. Many types of electronic equipment that have capacitors in the power supplies may be sensitive to the capacitor-switching

transients, even if the magnitudes are not severe. Finally, the capacitor-switching transients occur much more frequently than lightning transient—often every day.

Capacitors are an integral part of the power-factor correction and voltage control on the power system. Because loads and system conditions are always changing, the capacitors usually have to be switched on and off to accomplish their objectives of voltage control or power-factor correction. Conditions where the capacitor-switching transients can cause problems need to be identified. Problems can be avoided by changes within the end-user facility or by control of the capacitor-switching transients.

The Capacitor-Switching Transient

In the de-energized state, most common distribution capacitors are at or near ground potential. If the instant a capacitor is energized, the AC voltage waveform is at or near it's peak magnitude, the voltage will instantaneously assume the capacitor charge voltage, which is typically at ground potential. At the same time there will be a large inrush of current necessary to charge the capacitor to the line voltage. Due to system inductances, once the current flow into the capacitor is established it will not be able to change instantaneously when the capacitor reaches line voltage level. Instead, current will continue flowing into the capacitor causing the capacitor to overcharge. The overcharged capacitor will than reverse current flow causing current to flow back onto the power system thus establishing an oscillation of voltage and current between the power system and the capacitor. With the oscillation decaying quite rapidly, the voltage waveform returns to normal in typically less than a full cycle. The oscillatory voltage transient caused by capacitor switching is commonly referred to as a "Capacitor-switching transient."

As shown in Figure 8-12, in the initial oscillation where the capacitor overcharges, the magnitude of the voltage transient can theoretically approach two times the normal peak voltage (2 per unit). Usually, damping in the system causes the transient voltage to be less than 1.6 per unit.

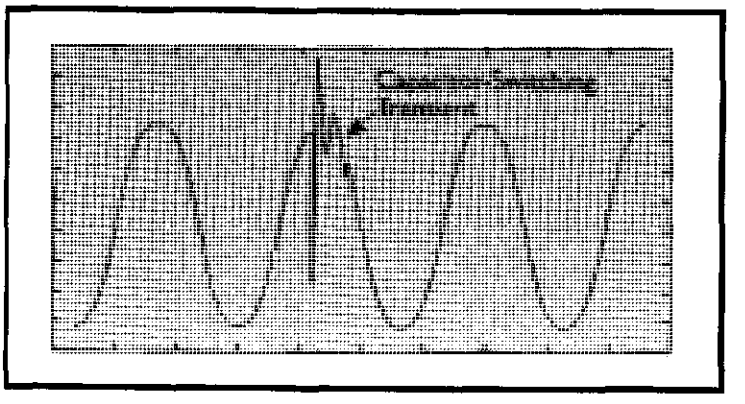


Figure 8-12
Typical Oscillatory Voltage Transient Caused by Capacitor Switching

Both the initial step voltage change and the oscillation can be important parts of the capacitor-switching transient. The initial step change is important because of the high rate of rise. This transient can couple across transformers into end-user facilities through the interwinding capacitances of the transformer. The resulting transformer "capacitance ratio" may be quite a bit lower then the transformers "turns ratio" (High voltage/Low voltage ratings). The transient voltage passed via the capacitance ratio will not be attenuated the same as the normal system AC voltages, resulting in higher magnitude voltage transients at the end-user facilities. Usually, the energy levels in this coupled transient are quite low, and conventional surge suppression equipment within the end use facility can prevent problems.

Equipment and devices on transmission and distribution systems are designed to handle transient voltage magnitudes well in excess of 2.0 per unit. Surge arresters on these systems are designed to protect at approximately 2.0 per unit and will not be significantly stressed by these transients. However, the transient oscillations occurring within end-user facilities can be a problem, depending on the types of equipment within these facilities. The lower voltage system concerns fall into two important categories:

Magnification concerns occur when lower voltage capacitors magnify a capacitor-switching transient originally initiated on the serving higher voltage system. The lower voltage capacitors could be on the utility distribution system (magnifying the transient for a transmission capacitor bank) or within end-user facilities (magnifying the transient for a transmission or distribution capacitor bank).

Nuisance tripping of sensitive loads can occur even if the transient is not magnified by lower voltage capacitors, some sensitive loads may be sensitive to the capacitor-switching transient. There is enough energy in many of these transients to cause nuisance tripping of adjustable-speed drives or other loads with electronic power supplies.

Magnification of the capacitor-switching transient occurs when the series combination of a step-down transformer and a lower voltage capacitor bank causes the energizing transient frequency to be magnified at the lower voltage capacitor. Figure 8-13 illustrates a circuit where this can be a concern. C1 is the switched capacitor on the utility supply system. C2 is a low-voltage, power-factor-correction capacitor within the end-user facility.

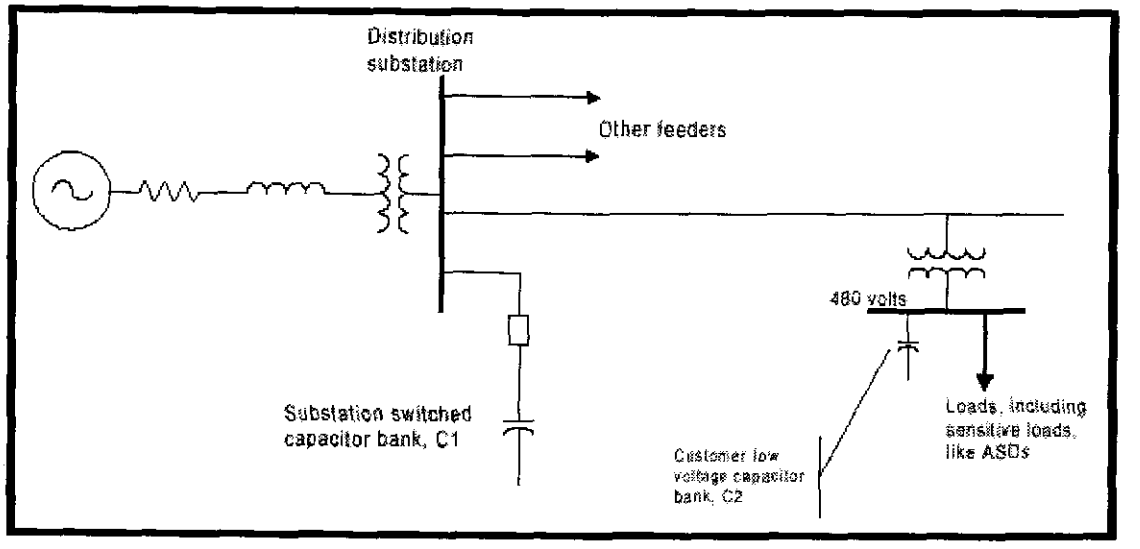


Figure 8-13
Example Circuit Where Magnification of Capacitor-switching transients Can Occur

Magnification is a concern when two conditions are met:

1. The switched capacitor bank (C1) is much larger (at least 8 times larger) than the lower voltage capacitor bank (C2).

2. There is not a significant amount of resistive load in the lower voltage system. Resistive load provides damping which prevents the magnification from being a problem. The resistive load on many distribution systems prevents magnification from being a problem when transmission capacitor banks are switched. However, many industrial facilities are dominated by motor load, which provides very little damping, and the magnification can be particularly severe in these facilities.

The magnified voltage waveform in Figure 8-14 is being limited by MOV arresters at the 480-volt bus, but it is still much more severe than the voltage at the switched capacitor location. This type of magnified transient is likely to cause arrester failures, electronic equipment failures, capacitor failures, or capacitor fuses to blow within the end-user facilities.

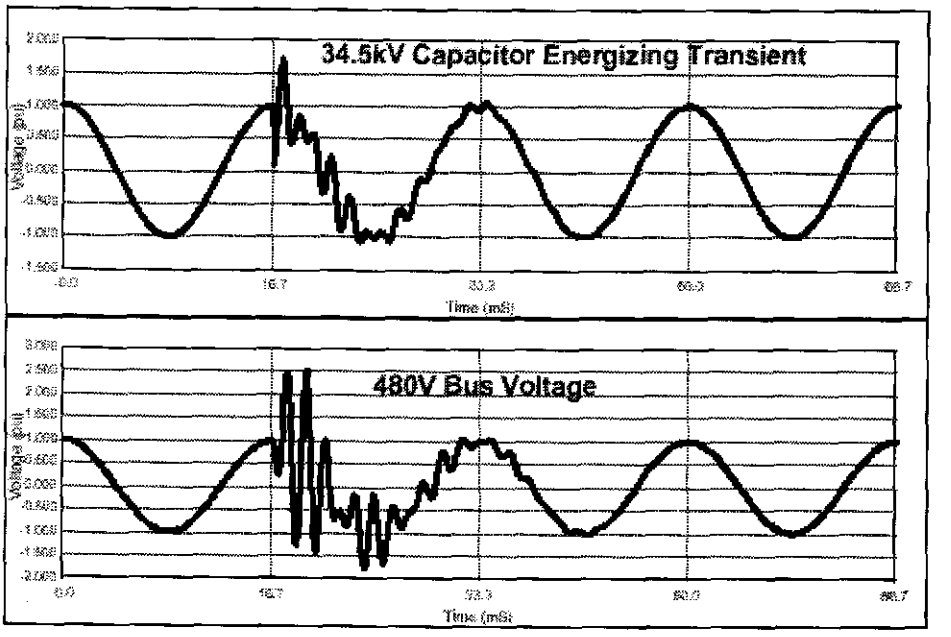


Figure 8-14
Waveforms Illustrating Magnification of Capacitor-switching transients

It is also important to note that the magnified transient can occur for a wide range of lower voltage capacitor sizes. Figure 8-15 illustrates an example case from a particular industrial facility. The curve shows the magnified transient voltage magnitude at the 480-volt bus caused by switching a 3-Mvar capacitor bank (C1) on the supplying distribution system. The overvoltage is given as a function of the 480-volt power-factor-correction capacitor (C2) is in service at the time the distribution capacitor bank is energized. The magnified transient exceeds 2.0 per unit for low-voltage, power-factor-correction levels ranging from 100 kvar to 500 kvar (right in the range of typical power factor correction for an industrial facility supplied by a 1500-kVA transformer).

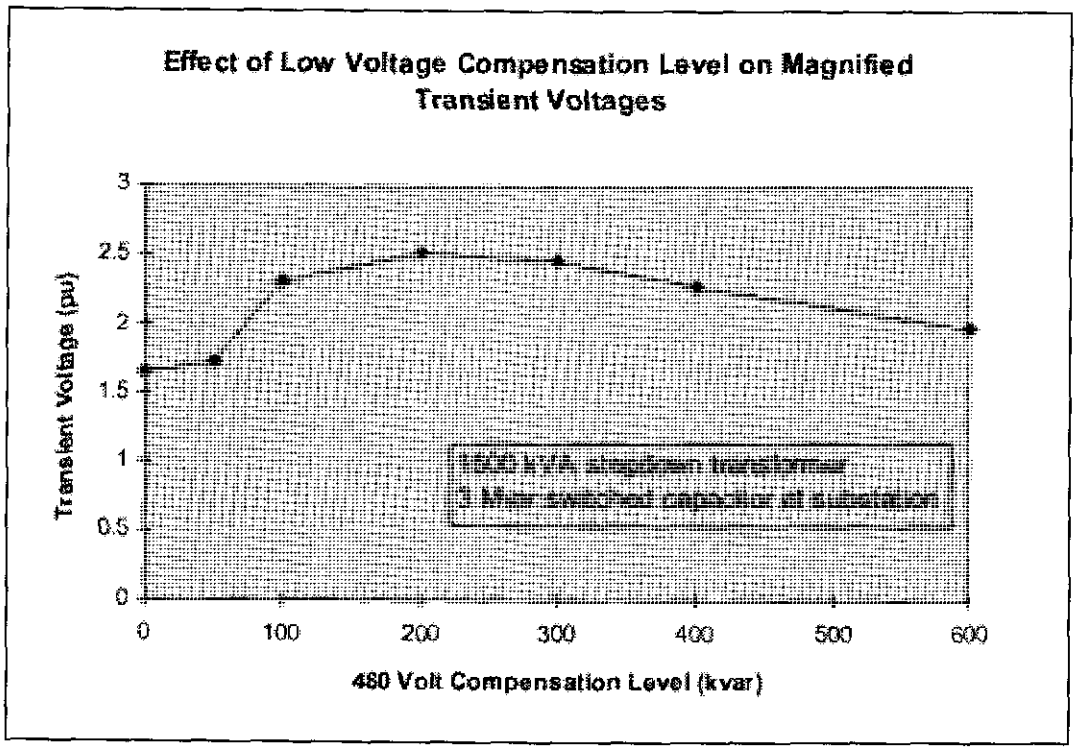


Figure 8-15
Effect of Power Factor Correction Levels on Magnification of Capacitor-switching transients

Solutions to the magnification problem can be implemented either at the switched capacitor bank or by modifying the configuration of the low-voltage, power-factor-correction capacitor. At the switched capacitor (C1), some type of switching control would have to be implemented. This could be by a synchronous closing control that closes the breaker contacts close to the zero crossings of the voltage waveform, or it could be "pre-insertion" resistors that are placed in series with the capacitor and the system before closing the main breaker contacts (to damp out the transient).

At the low-voltage level, configuring the low-voltage power-factor-correction capacitor as tuned banks, rather than shunt capacitor banks, can solve the problem. The series reactor in the tuned bank configuration detunes the resonant circuit and prevents magnification. This solution has the added benefit of controlling harmonic distortion levels within the end-user facility as well.

Figure 8-16 illustrates the effect of tuned banks for power factor correction on the magnified transient for the example case described previously.

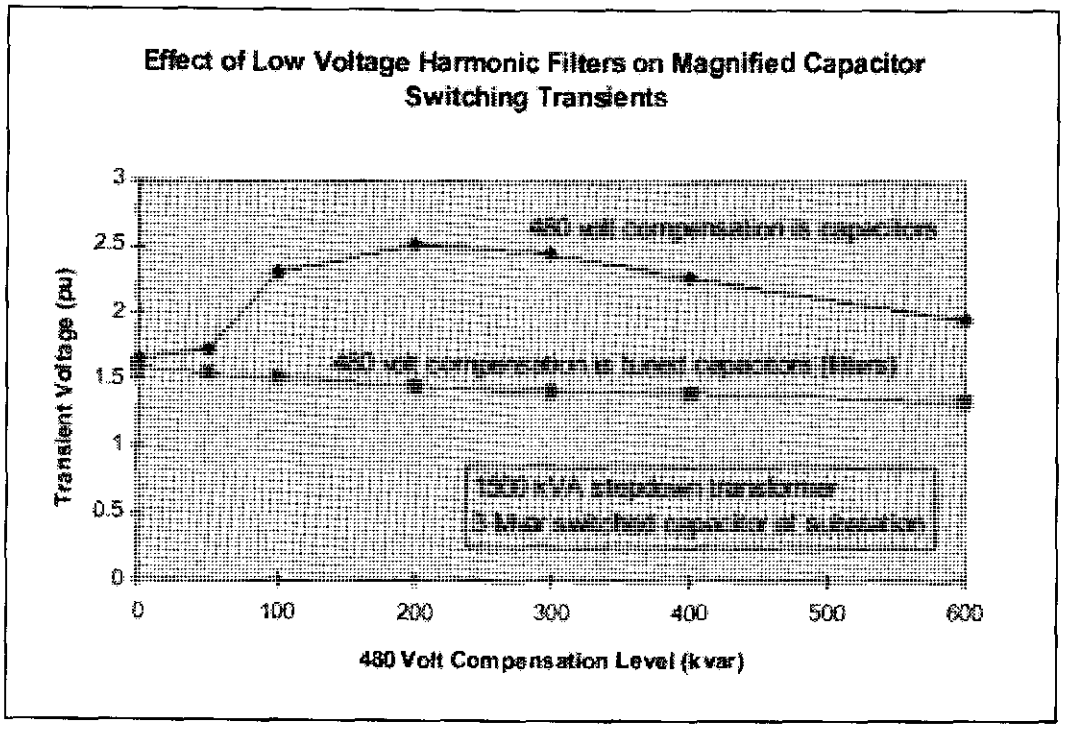


Figure 8-16
Effect of Tuned Capacitor Banks

Nuisance Tripping of Sensitive Loads

Even if there is no problem with magnified transient voltages that could cause arrester failures or equipment failures within end-user facilities, there still may be equipment that is very sensitive to the normal capacitor-switching transients. Adjustable-speed drives (ASDs) are the most common example of equipment that may trip for very low-magnitude capacitor-switching transients. A common type of ASD utilizes a voltage source inverter that takes power from a "DC link" capacitor within the drive. To protect the ASD inverter from damaging overvoltage conditions, ASD control are settings regarding the DC link voltage are set to be very sensitive.

A capacitor-switching transient can cause a transient current into the drive which charges up the DC link capacitor. Figure 8-17 illustrates a typical case. A typical setting for the DC overvoltage trip level is approximately 760 volts. This translates to less than 1.2 times the normal peak line-to-line voltage at the input to the drive. In other words, a capacitor-switching transient with a magnitude less than 1.2 per unit could cause the drive to trip. Other types of power electronic equipment with DC link capacitors can also be sensitive.

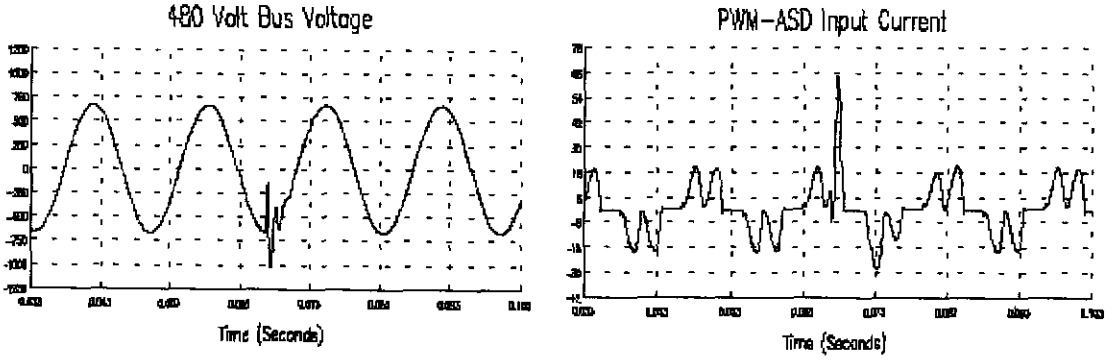


Figure 8-17
Effect of Capacitor-Switching Voltage Transient on Input Current Waveform of Adjustable-Speed Drive

This was a very severe problem for many end-users a few years ago. Evaluation of the problem and possible solutions indicated that the problem could be solved with an adequately sized choke inductance at the input to the drive. The choke inductance provides enough impedance to prevent the surge of current from charging up the DC link capacitor (see Figure 8-18). Before this was understood, most drives were sold without input chokes. Now, almost all drives are sold with either input line chokes or DC-side chokes that serve the same purpose. Because it is unrealistic to control capacitor-switching transients to levels less than 1.2 per unit, it is very important that drives and other power electronic equipment include sufficient input reactance to prevent tripping or other problems attributable to capacitor-switching transients.

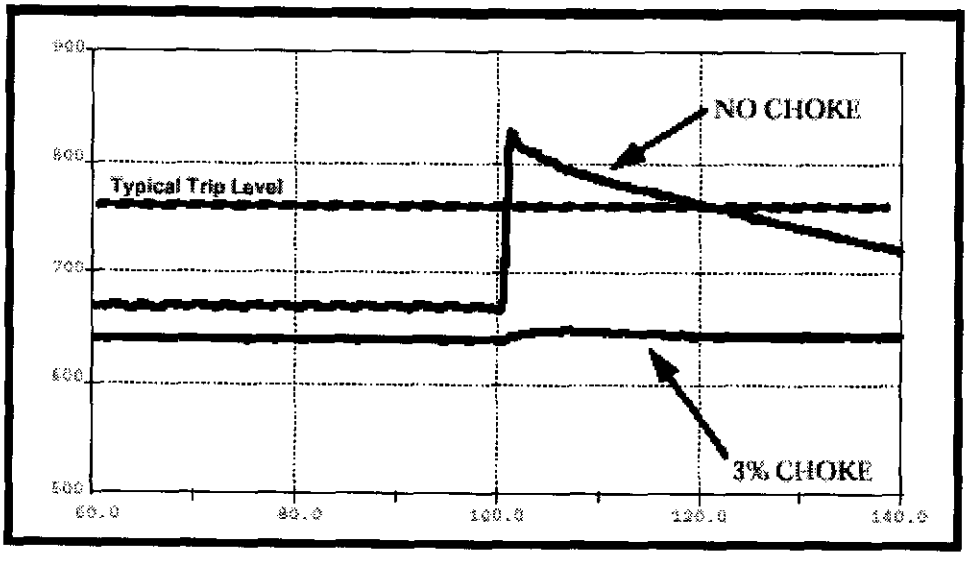


Figure 8-18
Effect of Input Line Choke (Reactor) on DC Link Overvoltage During Capacitor Switching

It is usually not necessary to control capacitor-switching transients with any special controls. However, when many end-users and lower voltage systems are susceptible to either magnified transient voltages or nuisance tripping of sensitive electronic equipment, it may be beneficial to consider controlling capacitor-switching transients associated with large capacitor banks at transmission voltages or at substations supplying industrial customers.

Utilizing synchronous closing controls for SF6 or vacuum breakers may mitigate capacitor-switching transients, or mitigation might involve utilization of pre-insertion resistors (or reactors) for breakers appropriately configured to accept this option. Note that the optimum resistor sizes to provide damping of capacitor-switching transients are significantly lower than the optimum resistor sizes for damping transmission line switching transients. Simulations using modeling software called Electro-magnetic Transient Program (EMTP) can be performed to determine the optimum resistor values, but they will generally be in the range 35-75 ohms.

9
POWER QUALITY MONITORING

Introduction

Since the completion of the EPRI Distribution Power Quality (DPQ) project—which produced a wealth of data summarizing power quality (PQ) levels on electrical distribution systems throughout the United States—there have been questions about the PQ levels on different systems and in different countries.

This chapter addresses issues surrounding the development of a PQ-monitoring program by:

- Developing methods for using power disturbance analyzers to evaluate voltage-related PQ problems on distribution systems and in end-use customer facilities.
- Evaluating and consolidating information on a group of unique PQ-related problems.
- Engaging standards-making bodies to begin addressing the identified elements such that utility commissions and regulators may have a well-defined information resource for any future power quality requirements.
- Defining the roadmap for the PQ picture from investigation methods to potential standards for responsibilities for customer load management.

Types of Power Quality Phenomena

Institute of Electrical and Electronics Engineers (IEEE) Std. 1159-1995 is the latest standard that defines various PQ events. The purpose of IEEE Std. 1159-1995 is to define PQ phenomena in an effort to bridge the gap between customer, manufacturers, and utilities in the PQ arena.

IEEE Std. 1159-1995 compiles a table of typical characteristics of power system electromagnetic phenomena. The values from IEEE Std. 1159-1995 are given in Table 9-1.

Table 9-1
Institute of Electrical and Electronics Engineers Standard 1159-1995, Table 2 – Categories and Typical Characteristics of Power System Electromagnetic Phenomena

Categories	Typical Spectral Content	Typical Duration	Typical Voltage Magnitude
Transients			
Impulsive			
Nanosecond	5 ns rise	< 50 ns	
Microsecond	1 μs rise	50 ns–1 ms	
Millisecond	0.1 ms 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
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
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
Voltage imbalance		steady state	0.5–2%
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%
Voltage fluctuations	<25 Hz	intermittent	0.1–7%
Power frequency variations		<10 s	

Transient Voltages

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

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

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

Transients caused by load switching (motor loads and contactor bounce) are high-frequency in nature and typically do not propagate through the system. On the other hand, transients caused by switching capacitors on the utility system can typically be seen throughout the power system and within facilities.

Fast rise times and high magnitudes have several effects on equipment. The energy in these transients can contribute to the breakdown of insulation in electrical equipment such as motors, transformers, and other equipment connected to the power system. Electronic loads, such as personal computers (PCs), can be damaged by these transients as well. The electronic power supply of a PC can be damaged from one transient with a relatively mild magnitude and rise time.

The IEEE Std. 1159-1995 breaks down transients into two categories:

- Impulsive
- Oscillatory

Impulsive

An impulsive transient is a sudden unidirectional change in the steady-state condition of either the voltage or the current. The polarity of an impulsive transient is either primarily positive or negative. Figure 9-1 is an example of an impulsive transient.

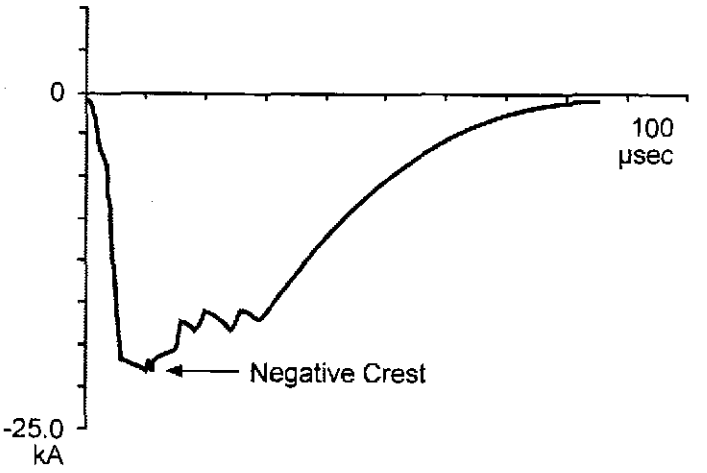


Figure 9-1
Example of an Impulsive Transient Caused by a Lightning Strike

Oscillatory

An oscillatory transient is a sudden bi-directional change in the steady state condition of either the voltage or the current. The polarity of an oscillatory transient is both positive and negative. Figure 9-2 is an example of an oscillatory transient caused by capacitor switching on a utility distribution system.

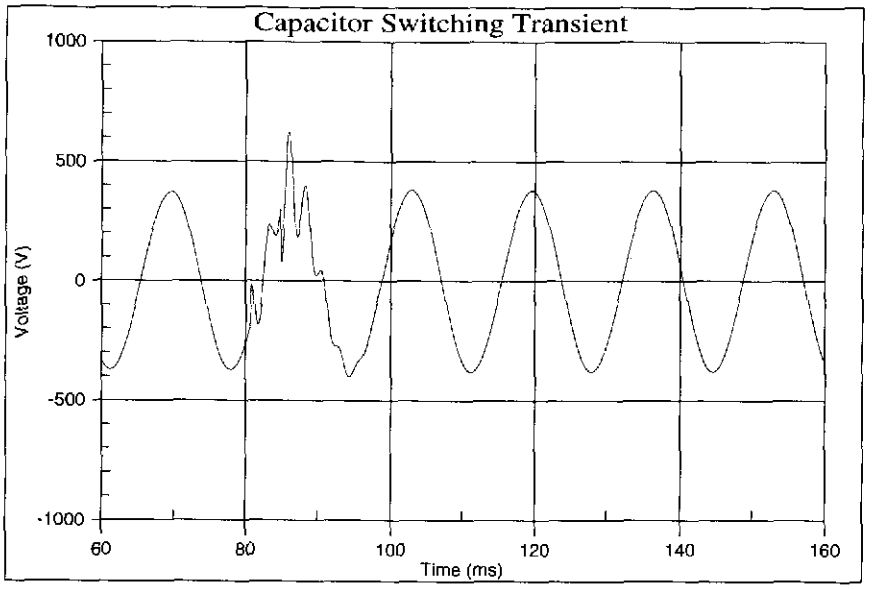


Figure 9-2
Example of a Typical, Low-Frequency Oscillatory Transient Measured on a Power System

RMS Voltage Variations

Root-mean-square (RMS) voltage variations can be classified as instantaneous, momentary, or temporary depending on the duration of the event. For the actual definition of these types of events, please see IEEE Std. 1159-1995. The main categories of classifications are:

- Short-duration variations
- Long-duration variations

Short-Duration Variations

Short-duration voltage variations—events such as voltage interruptions, sags, and swells that last less than a minute—are often the result of three conditions:

- A fault on the power system.
- Loose connections in wiring.
- The energization 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 problems for customer facilities. Short-duration variations can cause electronic equipment to malfunction.

There are three categories of short-duration voltage variations:

- Interruptions

- Sags (or dips)
- Swells

Interruptions

Interruptions can occur on power systems as the result of faults, equipment failures (such as cables, transformers, and breakers), or system operator errors. Interruptions are characterized by their duration because their magnitude is always less than 0.1 per unit (pu) by definition in IEEE Std. 1159-1995. The duration of the interruption that is initiated by a fault on the utility system is determined by the settings of the utility protective equipment.

When there is more than one feeder connected to a bus at a substation, a fault on any feeder will affect the voltage on the parallel feeders. When a fault occurs, all parallel feeders will experience a voltage sag. The faulted feeder will experience an interruption because of the operation of a protective device. When the protective device operates, the voltage on the parallel feeders will be returned to normal.

Depending on the protective practices of the utility, customers connected to the faulted feeder could experience as many as three instantaneous sags, two momentary interruptions, and one sustained interruption. Customers connected to the parallel feeders can experience as many as three instantaneous sags before the protective device locks out.

Figure 9-3 and Figure 9-4 illustrate the typical protective scheme of many U.S. utilities. Waveforms in the figures are representative of voltages on a faulted feeder and feeders in parallel with the faulted feeder, respectively.

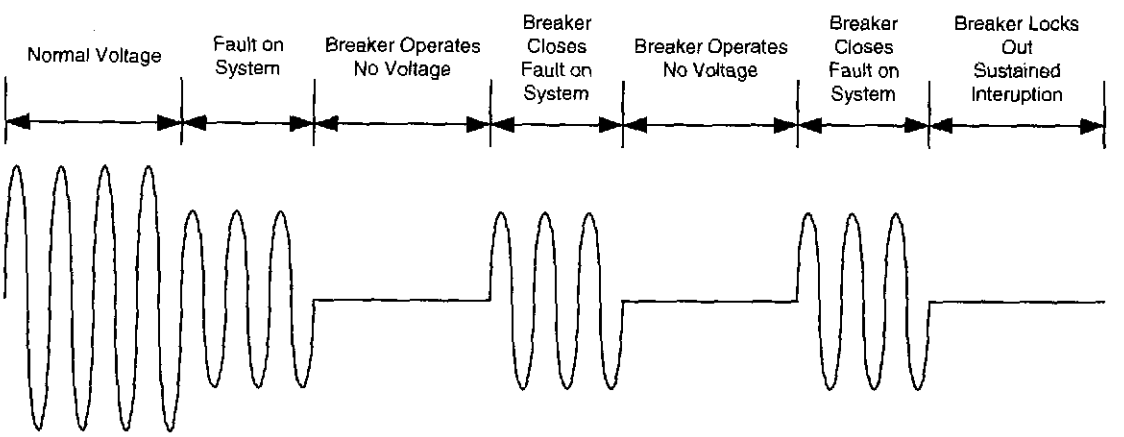


Figure 9-3
Typical Utility Protective Schemes During Faults (Faulted Feeder)

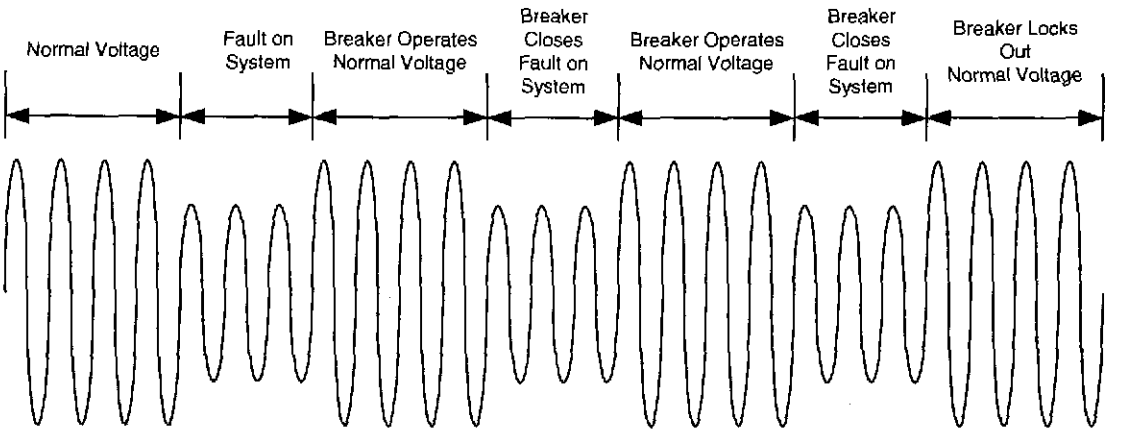


Figure 9-4
Typical Utility Protective Schemes During Faults (Parallel Feeder)

Sags or Dips

The term *voltage sag* is typically used to define an event that occurs on the power system where the voltage is depressed because of a system fault or other short circuit. When the term *sag* is used to describe this phenomenon, the accepted usage is "a sag to 75%," which means that the line voltage was reduced to 75% of nominal.

Voltage sags are typically caused by or associated with system faults. Systems faults are not the only cause of voltage sags, however. The starting of large motors or energizing of large loads can also produce voltage sags.

Depending on the sensitivity of the connected load, a voltage sag can have the same effect as an interruption. Some equipment will "trip off" or shut down when subjected to a sag to 80% of nominal for six cycles. Therefore, even if the load is not connected to the feeder that has experienced the fault, the load may shutdown. Figure 9-5 is an example of an instantaneous sag.

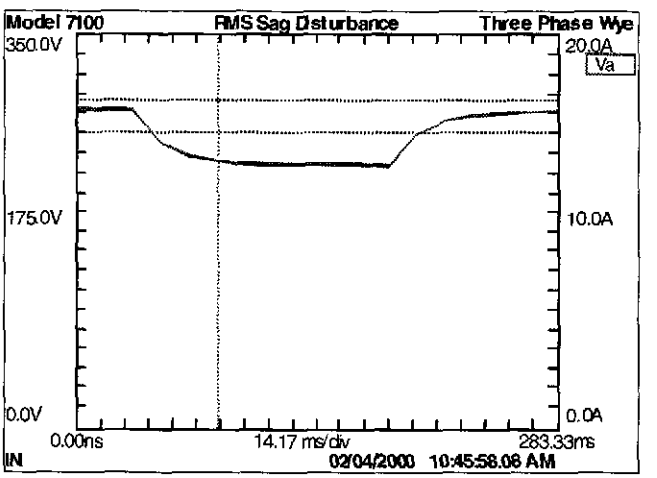


Figure 9-5
Example of an Instantaneous Sag

Swells

A swell is an increase in the RMS voltage or current at the power frequency. The duration for a swell is given in Table 9-1. The magnitude for a swell, like a sag, is defined by its remaining voltage. The magnitude for a swell will always be greater than 1.0 pu. Figure 9-6 is an example of an instantaneous swell.

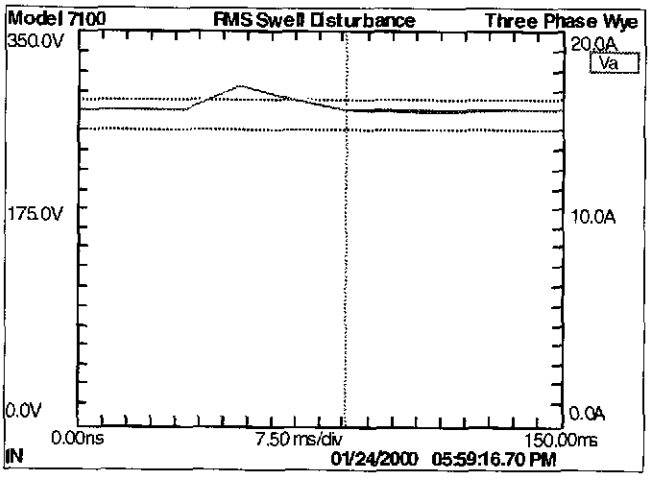


Figure 9-6
Example of an Instantaneous Swell

Like sags, swells are usually related to system faults. When a single line-to-ground fault occurs on a power system, a swell can occur on the unfaulted phase. The magnitude of the swell depends on the fault location, system impedance, and grounding practices of the utility.

Long-Duration Variations

Long duration variations can be classified as RMS variations that last longer than 1 minute. There are two standards that address these types of events: ANSI C84.1 and IEEE Std. 1159-1995.

In contrast to sags and swells, long-duration voltage variations are typically not caused by system faults. The most common cause of long-duration variations are system-switching operations and large load variations.

The IEEE Std. 1159-1995 has three subcategories for long-duration variations:

- Overvoltages
- Undervoltages

- Sustained interruptions

Overvoltage

There are many causes of overvoltages. Typical causes include capacitor-bank switching on the utility system and large loads being switched off the system.

Undervoltage

Undervoltages are the exact opposite of overvoltages. Their causes are the exact opposite as well. When a large capacitor bank is switched off the system, an undervoltage can occur. A voltage regulator on the utility system will typically correct the problem.

Utilities will, from time to time, reduce the voltage on their system in an effort to reduce the power delivery during peak times. This reduction in voltage is classified as an undervoltage. Loads connected to the power system can and are affected by undervoltages. Depending on the design criteria for the equipment and its tolerances, a 5% reduction in voltage may be sufficient to cause equipment to shut down. This is especially true if the equipment is already being supplied low voltage because of misapplied tap transformers or long cable runs.

Sustained interruptions

When the supply voltage is decreased to zero for a period of more than 1 minute, this is referred to as a sustained interruption. Interruptions in voltage that last longer than 1 minute are often the result of a system operation—such as a breaker trip or fuse blowing—and require intervention from the utility.

Sustained interruptions typically have the same effect on end use-equipment as momentary interruptions except that the equipment cannot be restarted. Another concern associated with sustained interruptions is cold load pickup. Cold load pickup occurs when a distribution system experiences higher than normal load currents because of a loss of diversity after a sustained interruption. This in turn could result in an undervoltage.

Flicker

Voltage fluctuations can cause lamps to flicker. Very small voltage variations are capable of producing variations in the luminosity of lamps that are annoying to the human eye. The sensitivity of humans varies with the frequency of the fluctuations. The International Electrotechnical Commission (IEC) 60868-0[15] document explains that the maximum value of flicker is attained at 10 Hz with a 0.3% voltage variation. The IEC 1000-4-15 document also describes flicker in two forms:

[15] IEC 60868-0, *Flickermeter – Part O: Evaluation of Flicker Severity,* International Electrotechnical Commission, 1991.

- Slow voltage variations
- Sudden voltage variations

Slow Voltage Variations

Slow voltage variations can occur because of a time-varying power consumption on the network. Loads such as arc furnaces and welders can cause these slow 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. Figure 9-7 illustrates an example waveform of a slow voltage variation. The modulation waveform for Figure 9-7 is at 5 Hz with a 10% voltage fluctuation. This case has been exaggerated for illustrative purposes.

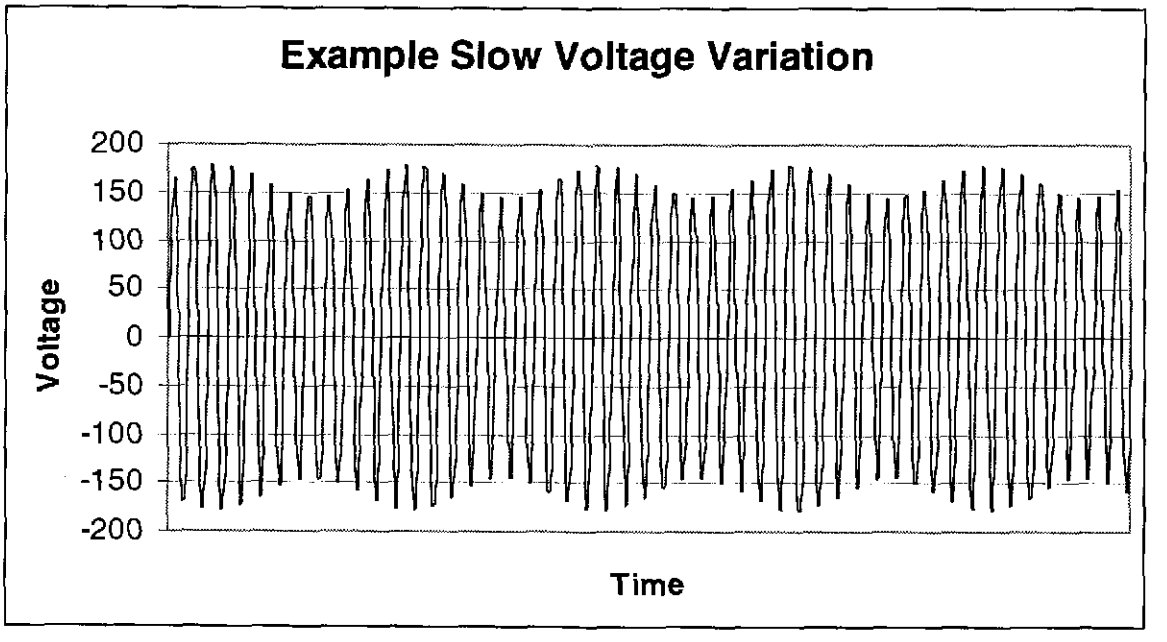


Figure 9-7
Example Waveform of a Slow Voltage Variation

Sudden Voltage Variations

Sudden variations of voltage, which are caused by the starting of large motors or other heavy loads, can also cause light flicker. These types of variations can be isolated or repetitive in nature. The amplitude of these sudden changes generally does not exceed 8% of the nominal voltage. In fact, the IEC goes on to state that voltage fluctuations of more than 10% of nominal are to be considered voltage sags or swells.

The sudden voltage variations are probably more of a nuisance to customers than the slow voltage variations. The most common cause for this type of flicker is from the cycling of large loads. When an averaged-size load (10 to 50 kW) is energized, it can draw large amounts of

starting current. This inrush in current is high enough to cause a 4% to 8% voltage drop on the secondary of the transformer. This voltage drop, or sag, causes the intensity of lamps to change rapidly, which is perceived by the human eye as a flicker.

Waveform Distortion

Waveform distortion is defined as a steady-state deviation from an ideal sine wave at the power frequency. There are two U.S. standards that address the issues associated with waveform distortion:

- IEEE Std. 519-1992
- IEEE Std. 1159-1995

IEEE Std. 519-1992[16]

IEEE Std. 519-1992 recommends guidelines for harmonic current injection and voltage distortion. To monitor in accordance with this standard, the monitoring instrument must be placed at the point of common coupling (PCC).

IEEE Std. 519-1992 applies to customers by limiting the amount of harmonic current the residence can inject into the power system. With the types of loads present in an industrial facilities, it is not uncommon for an end-use customer to exceed the harmonic current injection limits.

Using information from IEEE Std. 519-1992, supplied in Table 9-2, the harmonic current limits for a customer can be determined by the size of the customer load with respect to the size of the power system at the PCC. The short-circuit ratio (SCR) is the ratio between the short circuit current (I_{SC}) available at the PCC to the maximum fundamental load current (I_L).

[16] IEEE Std. 519-1992, *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems,* Institute of Electrical and Electronics Engineers, NY, NY, 1993.

Table 9-2
IEEE Std. 519-1992 Current Distortion Limits for General Distribution Systems (120 V Through 69,000 V)

Maximum Harmonic Current Distortion in Percent of I_L						
Individual Harmonic Order (Odd Harmonics)						
I_{SC}/I_L	<11	11 ≤ h < 17	17 ≤ h < 23	23 ≤ h < 35	35 ≤ h	TDD
<20*	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1000	12.0	5.5	5.0	2.0	1.0	15.0
>1000	15.0	7.0	6.0	2.5	1.4	20.0

Therefore, as the size of the customer load decreases with respect to the size of the system, the amount of harmonic current that can be injected into the system by the customer increases.

IEEE Std. 519-1992 also limits voltage distortion. However, these limits are the responsibility of the utility. If there is background distortion on the power system, linear loads will draw harmonic currents as a result of voltage distortion.

Waveform Distortion

Waveform distortion can be defined as any deviation of the power frequency from an ideal sine wave during steady state conditions. Waveform distortion is typically characterized by the spectral content of the deviation.

The IEEE Std. 1159-1995 defines five primary types of waveform distortion:

- DC offset
- Harmonics
- Interharmonics
- Notching
- Noise

Examples of each type of waveform distortion are given.

DC offset

When DC is present, in either the voltage or current, on an AC power system, it is defined as DC offset. Basically, when viewing a waveform where DC is present, the DC component will shift or offset the AC signal from the zero value of the time axis as illustrated in Figure 9-8. In Figure 9-8, the original sine wave has been offset by a DC component with a magnitude of 15% of the fundamental 60-Hertz component. While this amount of DC is relatively easy to see when compared to the original signal in our example, in actual measurements it may be necessary to perform a Fourier Transform on the signal to ascertain if the measured signal has a DC component.

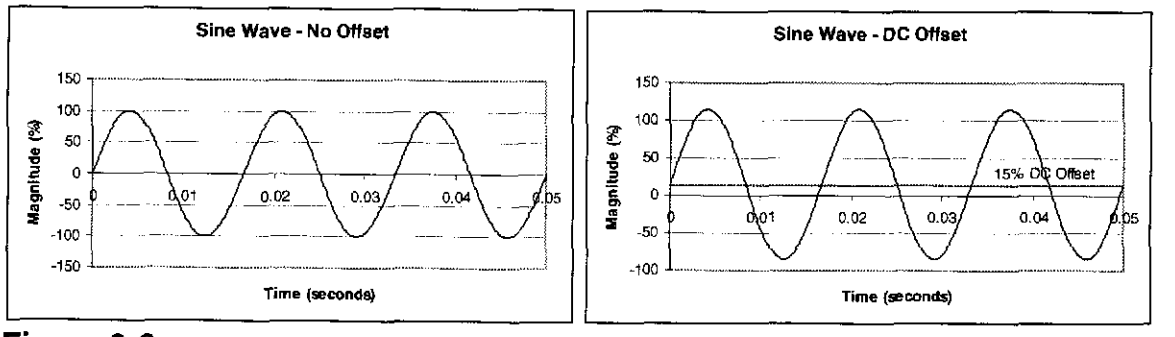


Figure 9-8
Example Plots Showing a 15% DC Offset

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

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

Harmonics

Harmonics are sinusoidal voltages or currents of frequencies that are integer multiples of the power system fundamental frequency. When the harmonic voltages or currents combine with the fundamental power system voltages or currents they produce waveform distortion. Figure 9-9 illustrates waveform distortion. The waveform and associated spectrum in Figure 9-9 represent the input current to a six-pulse AC adjustable-speed drive (ASD).

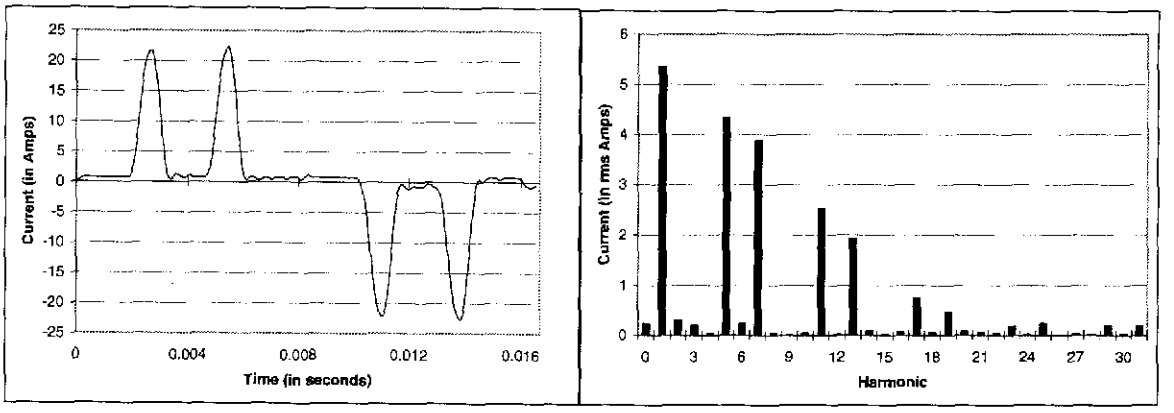


Figure 9-9
Example Illustrating Harmonic Distortion

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

Interharmonics

Interharmonics harmonics are a special case of harmonics. Harmonics are integer multiples of the fundamental power frequency. Interharmonics are not integer multiples of the fundamental power frequency. Interharmonics are a result of many devices like cyclo-converters, inductions motors, and arcing devices (for example, arc furnaces, magnetic ballasts, welders)

Notching

Notching occurs because of the normal operation of power electronic devices. When power electronics of a rectifier operate properly, the current is commutated from one phase to another phase causing a momentary short circuit between the two phases. This produces notching in the voltage waveform similar to the example illustrated in Figure 9-10. Notching is classified as a waveform distortion. The notching occurs continuously and is therefore characterized by the harmonic spectrum of the voltage. Given the frequency components associated with the notch, it may be difficult to characterize the frequency of the notching with standard harmonic measuring instruments.

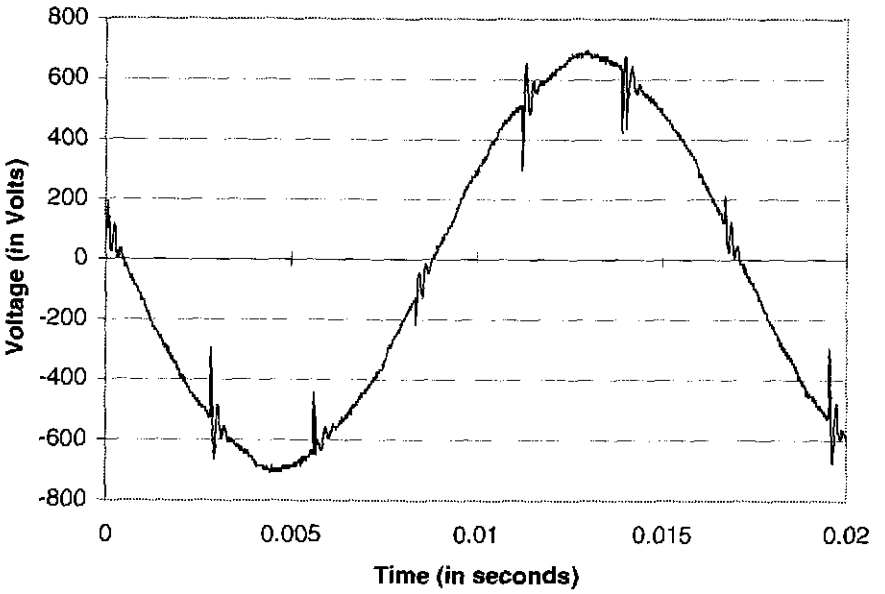


Figure 9-10
Voltage Notching Caused by a DC Drive

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

Noise

Electrical noise is unwanted signals that are superimposed on the power frequency. The spectral content for this noise is typically less that 200 kHz. The most common sources of electrical noise are arcing loads and power electronics. Loose connections or improper wiring can often intensify the noise problem.

High-efficiency electronic ballasts and dimmer switches are known to produce noise on the wiring of residential buildings. Figure 9-11 illustrates an example of noise measured on a power system.

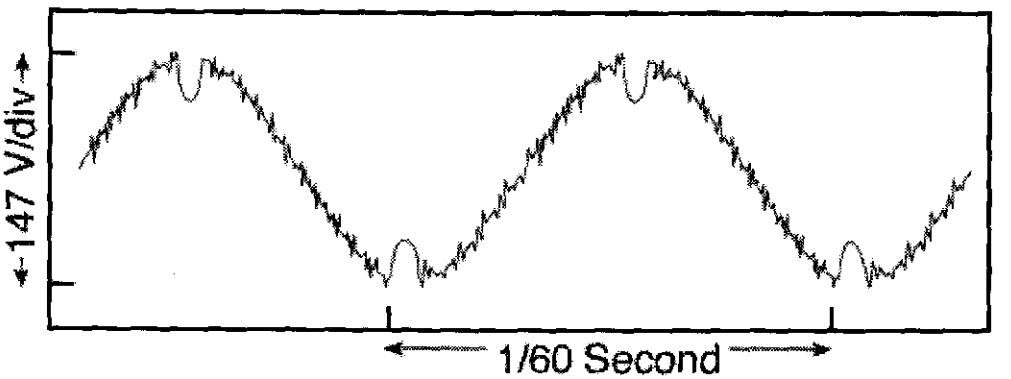


Figure 9-11
Example of Noise Measured on a Power System

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

Wiring and Grounding

Perhaps one of the most common problems related to PQ is wiring and grounding. It has been reported that approximately 70 to 80 percent of all PQ-related problems can be attributed to faulty connections and/or wiring. It should be noted that a majority of the PQ monitors available on the market do not perform any type of wiring or grounding check. However, several of the monitors available do measure neutral-to-ground voltage and check for neutral and ground reversal.

A typical monitoring system will not incorporate the use of a PQ monitor that performs grounding measurements. It should be noted, however, that wiring and grounding issues could exacerbate the problems associated with the other PQ phenomena mentioned previously. Therefore, a thorough wiring and grounding audit should be performed before the installation of any monitoring equipment at the service entrance. Any problem found in a grounding system should be corrected before the start of a monitoring project.

Monitoring Objectives

Before any monitoring project is undertaken, the objectives of the monitoring project must be defined. There are three main reasons why PQ monitoring is performed:

- Diagnostic monitoring
- Evaluative monitoring
- Predictive monitoring

Information on the purpose for monitoring, the quantities to be monitored, and monitoring period are required. These parameters help define the type of monitoring to be performed and,

ultimately, the end product of the monitoring project. The end product can be the installation of a PQ mitigation device, the development of PQ service contracts and benchmarks, or the development of maintenance practices on the power system.

Diagnostic Monitoring

Diagnostic monitoring is the most common type of PQ monitoring performed at the customer level. Diagnostic monitoring is often referred to as troubleshooting. This type of monitoring generally involves placing a monitor at a customer facility after a problem has been reported to the utility.

Once the monitor has been installed, a survey of the facility is generally performed to determine what problems the customer has been experiencing. Often, the customer is given a disturbance recording form, as shown in Figure 9-12, to record any malfunctions of appliances that occur during the monitoring phase.

Residential Disturbance Recording Form

Date: _____

Time: _____

Name: _____

Address: _____

_____

Phone: _____

Description: _____

_____

_____

_____

_____

Equipment: _____

_____

Manufacturer: _____

_____

Ratings: 120 Volt _____ 240 Volt _____

Figure 9-12
Typical Residential Disturbance Recording Form

The end product of diagnostic monitoring is solving the PQ problem. By using monitoring, appliance malfunctions can be correlated with events on the power system. Once the type, quantity, and severity of the events are known, solutions can be developed to mitigate the problems associated with the PQ events.

Evaluative (Benchmarking) Monitoring

Evaluative monitoring is used to evaluate or "benchmark" the PQ levels on a system. This type of monitoring is typically performed at the utility's system level. However, customer PQ benchmarking can be performed and does have its merits.

Evaluative monitoring normally implies that the data-gathering method of a monitoring project results in data that can be statistically validated. Several large evaluative monitoring projects at the distribution level have been performed in the past by EPRI and other research organizations. These projects focused on PQ levels as they pertain to distribution and transmission systems. Several of these projects are described below.

EPRI Distribution Power Quality Project

The EPRI Distribution Power Quality (DPQ) Project was a two-year evaluative monitoring project to characterize PQ on the primary distribution systems across the United States. The purpose of the study was to build a database of PQ data and statistics typical of U.S. distribution systems that could be used as a benchmark for other PQ investigations. For additional information on this project, see EPRI TR-103208 and TR-106294-V1, V2, and V3.

Utility A

Another example of evaluative monitoring is the 1996 study involving a single California utility. The utility approached EPRI to discuss establishing a monitoring project that would involve the design of a system similar in design to the EPRI DPQ project. Because a primary goal of the project was to compare the utility's PQ levels with EPRI DPQ PQ levels, the project team used the same monitoring hardware and software used in the EPRI DPQ project.

Utility B

Another utility initiated its Distribution System Power Quality Assessment Project in 1995. The project consisted of monitoring at medium-voltage distribution substations. This utility wanted to obtain statistics on the magnitude, duration, and frequency of voltage sags, swells, and transients that occur in its distribution system, as well as characterize harmonic distortion.

The End Product

The end product of evaluative monitoring is a collection of PQ events that "benchmark" or give a base value of the PQ levels on the system under test. The data can be used to develop charts and graphs that describe the overall PQ levels on the system. Typically, utilities will benchmark their system over a one-year period. Each successive year's data is compared to the previous year's data, which provides a roadmap for the utility. This roadmap informs the utility of the trend of the PQ on their system. Figure 9-13 illustrates a typical chart resulting from an evaluative monitoring project.

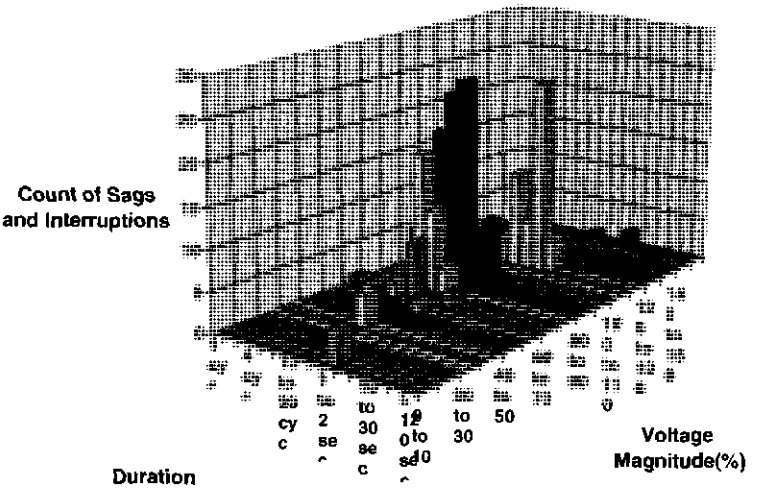


Figure 9-13
Typical Three-Dimensional Bar Chart Based Upon a System-Wide Monitoring Project

Typically, a report is developed that summarizes the findings of a monitoring project and even gives recommendations if trouble spots are found within the system. More importantly, an evaluative monitoring project provides a baseline for the system. The data from one year to the next can be used to compare and evaluate the PQ levels on the system. A utility can compare yearly data to determine if it needs to improve in any areas or if the PQ levels on the system are a concern.

Results from this type of monitoring are often used to verify computer models used in simulations. By having baseline information on PQ and power flow, simulation tools can be employed to help predict levels of PQ in the future and for system changes.

Predictive Monitoring

Predictive monitoring takes a different approach than evaluative monitoring. Predictive monitoring is performed to estimate or predict the PQ levels on a particular system. Evaluative monitoring is used to report only actual PQ levels. Predictive monitoring results are used to develop system models that allow engineers to predict the PQ levels on the system where monitors are not present.

When performing predictive monitoring, certain information needs to be gathered.

- Types of electrical disturbances and system conditions that concern the utility
- System parameters that affect PQ levels
- Characteristics of PQ variations as a function of the system parameters
- Data from other similar monitoring projects

Several projects are underway at EPRI to develop state estimation software that will be used in conjunction with monitoring to determine the PQ levels on different systems, at different voltage classes on the same system, and at a future date.

The placement of the monitoring equipment is crucial to this type of monitoring. The site-selection process outlined in this report is for an evaluative type of monitoring project. Therefore, the methodology for performing a predictive type of monitoring project will not be addressed.

What Needs to be Monitored?

In a word, everything. In a perfect world, with endless resources, the PQ monitor would capture everything when an event happened. However, when performing system-wide monitoring projects, this questions needs to be considered seriously.

Monitors typically measure only two quantities: voltage and current. All other parameters—such as kilowatts (kW), kilowatt-hour(s) (kWh), power factor (PF), and total harmonic distortion (THD)—are all calculated values or values derived form the measured quantities.

Voltage

Because the utility supplies voltage to the customer and the customer's load draws current from the system, voltage is perhaps the most important parameter to measure. Any deviation in the voltage level or waveform will typically manifest itself in the load current. If the monitoring site is a three-phase site, the instrument should be configured to measure a three-phase, four-wire system. Most commercially available instruments have the capability to be configured as:

- Three-phase, three-wire (Delta)
- Three-phase, four-wire (Wye)
- Single-phase, three-wire (typical residential service)
- Single-phase, two-wire (typical 120-V outlet)

Current

Monitoring the phase currents can be invaluable. In fact, characterizing loads on the system requires the measurement of phase currents. Phase currents are also required to determine power or energy parameters. Information pertaining to the location or direction of an event can be derived if the phase currents are captured during an event.

Characterization of Power Quality

Customer PQ monitoring is significantly different from distribution- or transmission-level PQ monitoring. However, there are some overlaps in objectives. Important objectives for customer PQ monitoring include:

- To identify the PQ phenomena that affect customer facilities. Once the phenomena are determined, the appropriate PQ instrumentation and transducers can be selected.
- The identification of distribution-system configurations and parameters is crucial to the success of a customer PQ monitoring program. Information pertaining to quantity, frequency, and magnitude of recorded events are all affected by the system configuration. These system parameters or system configurations need to be addressed and correlated to the actual system events.
- The use of standards is required in any monitoring project. The standards are used to correctly identify and define the PQ phenomena.

Table 9-3 illustrates the parameters that are considered important in characterizing PQ for customer facilities.

Table 9-3
System Configurations and Parameters That Affect Power Quality

Voltage level on distribution system	Number of feeders from substation
Specific number would be given	Specific number would be given
Number of customers served from transformer	Circuit type
3 or fewer	Single phase
4 to 7	Two phase
8 or greater	Three phase
Overhead vs. underground service	Load density
Overhead	Urban
Underground	Suburban
Combination (% overhead and % underground)	Rural
Circuit configuration	Load type
Radial	% Residential (% given in kW)
Looped	% Commercial (% given in kW)
Network	% Industrial (% given in kW)
Circuit components	Customer transformer size
Reclosers	25 kVa
Fuses	50 kVa
Capacitors	Other
Regulators	Customer voltage
Total circuit length	120
Specific mileage would be given	240
Distance of monitor from substation	Substation transformer size
Specific mileage would be given	Specific number would be given
	Substation voltages

Site Selection Process

Introduction

Designing the methodology by which sample sites might be selected for a system PQ study is a challenging undertaking. In part, this is because a number of factors that might have a significant effect on the nature of the design are not yet known, such as the number and distribution of participating utilities.

This chapter identifies variables that may affect the accuracy of a national or system PQ study and discusses some of the challenges that must be addressed in developing a final site-selection process for this project.

Objectives of the Project As They Affect the Site-Selection Process

As it is currently conceived, a national or system PQ project is intended to achieve the following objectives:

- Provide information to both utilities and to appliance manufacturers about the typical PQ experience of customers in:
  - Characterizing typical voltage variation patterns and
  - Characterizing the frequency of occurrence, magnitude, duration, and character of power quality events, including transients, short-duration variations, long-duration variations, steady-state regulation range, and harmonic distortion.
- Provide information to utilities about the way in which the typical voltage deviations, and PQ events, experienced by customers are affected by the characteristics of the distribution-system connection through which individual customers are served.
- Provide sponsoring utilities with enough PQ information about their own distribution circuits to benchmark their expected PQ performance.

Assumptions

For purposes of developing an approach to site selection for the proposed project, we have assumed that the following things are true:

- The power delivered to individually metered customer will be the unit of analysis (the unit for which data will be captured and analyzed).
- While manufacturers might wish to know the PQ experience at the level of individual loads, the project will likely need to measure at the entire facility level or at the step-down transformer level where several loads are connected in parallel.
- All customers that are individually metered for electricity service will constitute the universe of interest (that is, the population to which the data will be extrapolated).
- The data to be collected and analyzed will include multiple quantitative measures, some of which will typically vary over a relatively narrow range (such as typical voltage delivered), while others may vary over a wide range (such as the number of transients).

- It will not be possible to estimate the typical standard errors for all of the quantitative measures to be captured.
- The installed metering devices will be capable of measuring all variations from steady-state to transient.

An Initial Approach to Site Selection

A simple site-selection process might be a random sample of all metered individual customers. Such a sample could be easily drawn from one of the many available lists of customers served, and then screening out the customers that are not individually metered. Unfortunately, this option is not available to this project for three reasons:

1. Not all customers will be available to be sampled because not all utility service territories will contribute to the sample pool.

2. Utility participants need information about the distribution-system connection for each customer, and it will be difficult, if not impossible, to identify the characteristics of a distribution-system connection for a given customer if that customer was not selected by going "through" the distribution system.

3. Even if the problem in reason 2 could be solved, there is a need to ensure that sufficient variability exists in distribution system characteristics associated with the sampled customers. Customers will need to be sampled in ways that ensure that important differences in distribution system characteristics are adequately represented in the sample.

This suggests that the project will require a multi-stage design, sampling through distribution system characteristics to arrive at a sample of customers.

The implication is that the specific process by which the multi-stage sampling should proceed will need to remain an open question until the abilities of the participating utilities to provide information about their circuits and customers is known. Our preference would be for a methodology that allows the project team to use some version of the circuit characteristic variables to create 20 to 50 categories of circuits. The circuit categories would be defined as combinations of circuit characteristic variables that represent common types of circuits and that are hypothesized to account for significant variability in the PQ that customers experience.

If all of the circuits in all of the participating utilities could be identified and allocated to these categories, then individual circuits could be sampled from those categories at known and non-zero rates. Given this, a statistically valid sample of circuits, at least from among those circuits served by participating utilities, can be developed.

The second stage in this sampling methodology would be to sample customers for the installation of meters from within all of the residences served by the sampled circuits within a given circuit category. The result would be a statistically valid sample of customers from among the customers served by the participating utilities that would also ensure the ability to evaluate the impact of distribution-system characteristics on the different PQ experiences of customers.

Sample Size

Sample sizes are a function of cost, accuracy of results desired, and the variability inherent in the measures being made. As a general rule, the more accuracy desired, and the larger the variance in the measures being made, the larger the required sample size. These issues pose a perceived problem because several of the important measures are expected to have a good deal of variance.

This variance and the corresponding need for a very large sample size can be adequately addressed through selective data filtering. For example, the range of transients from site to site could be less than ten to more than one thousand if all recorded transients are counted. However, if we consider (or query for) only transients greater than 350 V (zero to peak), the numbers may be more in the range of zero to ten over the population. Each disturbance type should be adequately filterable using either magnitude, duration, or a combination of the two.

Site Measurement Duration

The remaining question in this discussion is that of how long meters should be in place at a given location. The short answer to this question is that the meters should be in place long enough to accurately represent the typical experience of customer, capturing both the typical baseline experience and the unusual, but predictable, variability-from-baseline experience. If, for example, customer PQ experience is substantially more variable during the summer (because of peak demand days and lightning strikes, for example) than it is during the rest of the year, then it will be important to capture both the summer experience and enough of the rest of the year to ensure that the impact of the summer months is not over-represented. This suggests that metering periods of at least one full year would be appropriate.

Monitoring Equipment

Introduction

Monitoring PQ is difficult because of the wide range of disturbances that must be characterized. Disturbances range from impulses, with rise times in the microsecond range, to long-duration variations in RMS voltage magnitude. At the same time, harmonic distortion and other continuous phenomena may also need to be monitored.

Disturbance monitoring requires that voltage be continually sampled but recorded only if the signals exceed specified values. Most types of disturbances, with the exception of voltage variations, require that currents be recorded as well.

Continuous monitoring requires that the instrument periodically record voltage and current waveforms. Continuous monitoring is required to adequately characterize waveform distortion and voltage flicker. It is not acceptable to record data only when a threshold is exceeded, because average levels may vary widely over time. If the threshold is set too low, the instrument records continuously, and its storage capacity is quickly exhausted. However, raising the threshold results in long periods of time where no data is recorded at all.

The next three sections (Signals to Monitor, Data Storage and Communications, and Measurement Technique) list the capabilities of various PQ monitoring instruments that may be used to develop a specification for a PQ monitor.

Signals to Monitor

For customer monitoring, it is assumed that the monitor will be installed at the neutral-to-ground bond. Therefore, there should be no need for neutral-to-ground measurements. In general, the monitoring instrument must have the capability to measure voltage and current on all phases. This is particularly true for monitoring to identify what types of disturbances are causing problems. However, monitoring all voltages and currents is not always necessary. For example, voltage-only monitoring can be used for characterizing short- and long-term voltage variations. Single-phase monitoring is acceptable for tasks such as analyzing harmonic trends on a feeder dominated by balanced three-phase loads.

Multiple-channel monitoring instruments should provide an option to disable individual channels for various monitoring applications. This prevents recording of meaningless data from unused channels. The ability to correct transducer connection errors using the instrument control software is very desirable. This may be necessary if a CT is installed using the wrong polarity for current flow.

Data Storage and Communications

As discussed in greater detail in this section, the capability to transmit disturbance data to a remote computer is a virtual necessity for most monitoring projects. In certain applications, such as short-term diagnostic monitoring, remote data transfer is not practical. Therefore, it is important that the instrument have the capability to store at least one week of data. This can be accomplished with disk storage or random-access memory (RAM).

It is important to consider the efficiency of the instrument with regard to storage space. The use of sophisticated algorithms for storing transient events and distorted waveforms can reduce storage requirements to less than 5% of that currently required by some monitoring instruments.

Measurement Technique

Although analog methods have been used for disturbance monitoring in the past, state-of-the-art instruments employ analog-to-digital conversion to provide sophisticated disturbance-detection algorithms. Digital analysis requires sampling of the 50- or 60-Hz waveform at a rate suitable for graphic reproduction and for additional analyses. A sample rate of 128 samples/cycle provides the necessary sampling rate to provide good resolution of true RMS detection, spectral data up though the 50th harmonic, and sufficient sampling speed for IEC flicker measurement detection if incorporated into the meter.

Various measurable electromagnetic phenomena found on power systems are discussed in IEEE Std. 1159-1995, *IEEE Recommended Practice for Monitoring Electric Power Quality*. This

standard provides categories and descriptions important to be able to classify measurement results and to describe electromagnetic phenomena that can cause PQ problems. The following paragraphs discuss the various categories of PQ disturbances described in the IEEE Std. 1159.

Transient Detection

Transients are categorized as either impulsive or oscillatory. Transients are considered an important factor in PQ monitoring, especially lightning-induced impulses. If available in a selected monitor, impulse measurement may be a simple text report indicating date, time, and positive and negative peak magnitudes of the measured impulse. Low-frequency oscillatory transients may be recorded as waveform disturbances.

Short-Duration Variation Detection

Short-duration variations are categorized as instantaneous, momentary, or temporary, based on the duration. Depending on the selected monitor, the instantaneous variation are usually captured as a waveform event and displayed graphically showing the cycle-by-cycle waveform. A momentary event may show up as both a waveform event and an RMS event. Because of the long nature of temporary events (3 seconds to 1 minute), these are typically displayed as RMS disturbances. An RMS measurement is basically an RMS strip chart of the event that ignores the waveform data. RMS disturbance plots provide data on RMS disturbances while describing a sag or swell event. Interruptions are typically displayed as RMS events as well.

Long-Duration Variation Detection

Long-duration variations (> 1 minute) are sub-categorized as sustained interruptions, undervoltages, and overvoltages. With the exception of one make of monitor, most will not capture an entire long-duration variation. Instead, a long-duration variation may be reported as two RMS variations: the first when the variation exceeds a threshold and the second when the variation returns back within the threshold.

Steady-State Analysis and Harmonic Detection

Depending on monitor architecture, periodic sampling of monitored channels provides trends from RMS calculation and waveform capture. The results of periodic RMS calculations are recorded as average, minimum, and maximum RMS values plus frequency over a defined interval. Depending on the monitor, the interval may be user-defined or as defined by the monitor. Waveforms are captured for a number of cycles to enable the calculation of power, power factor, total harmonic distortion, individual harmonic magnitudes, and phase angles. Although harmonics are not typical problems in residences, harmonic profiling may be important to provide a reference of harmonic levels that may be used in the future to track changes in customer harmonic levels as more and more power electronics are added to customer loads.

Voltage Fluctuation Detection

"Voltage fluctuations are systematic variation 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 to 1.05 pu. Voltage fluctuations generally appear as a modulation of the fundamental frequency (similar to amplitude modulation of an AM radio 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 to 8 Hz."[17]

Because voltage fluctuations of this type affect the lighting intensity at a rate perceptible to the human eye, the resulting lamp flicker has been used to describe the voltage fluctuations as *voltage flicker*. This is a term IEEE 1159 suggests should be avoided.

European standard IEC 61000-3-3 discusses "Limitation of voltage fluctuations and flicker in low-voltage supply systems for equipment with rated current $\leq$ 16A." Another European standard IEC 61000-4-7 provides general guidelines how to measure "flicker." Newer PQ monitors have the ability to measure "flicker" based on the IEC standards, while others base measurement of voltage variation on the "GE Flicker" curve.

The types of loads that cause lights to flicker in residences are typically large motor loads switching on and off. Wiring problems such as a loose neutral can also cause flicker. These types of disturbances should be picked up as an RMS disturbance or waveform event. Therefore, unless there is a need to establish a baseline for voltage fluctuations, there is no need to measure this parameter during customer load monitoring. If there is a need to establish a trend for voltage fluctuations, careful consideration should be given to which method should be used. Most likely a form of the IEC standard will be accepted.

Review of Current-Technology Monitoring Equipment

There are a large variety of monitors available today to address PQ monitoring needs. Typically, the cost of these monitors increases with the capabilities. Portable units are more expensive than hardwired units, single-phase units are less expensive than three-phase devices, and voltage-recording units are less expensive than voltage- and current-recording devices.

Voltage-Only Monitors

There are a few vendors that supply call-back units that are designed simply to call the utility in the event of a power interruption. These devices plug into a power receptacle and a nearby telephone line. Because of their ease of installation, these devices are considered portable. More sophisticated, portable voltage-only monitors may plug into a receptacle and provide data using a paper printout or the data maybe downloaded to a PC through a serial port connection. Portable units are also available for connecting to terminals in power panels. When using these devices,

[17] IEEE Std 1159 – 1995, Page 23

care must be taken to return the panel cover once the power connections are made to the monitor or appropriate measures should be taken to ensure against potential shock hazards from exposed live terminals.

Hardwired monitors are typically installed as permanent or semi-permanent monitors. Under EPRI sponsorship, Dranetz-BMI developed the model 3100 commonly referred to as the PQPager. The PQPager monitors voltage only, in either single- or three-phase mode. This device connects to a telephone line for transmitting the data on a scheduled basis or for paging programmed telephone numbers when a PQ event triggers the meter. This unit can easily be made portable simply by wiring in a three-wire cord and three-pronged plug. Probably the least intrusive of monitors available are meter-based devices. These devices may be integrated into a meter socket extension unit, or the meter might have PQ monitoring capability built in. Because the utility controls servicing of the metering equipment at most residences, long-term PQ monitoring might be best achieved using a meter-based monitoring system.

The majority of these systems use some sort of threshold, which must be exceeded to trigger an event record, whereas steady-state data is achieved by periodic sampling. There is at least one monitor that samples the waveform and constantly adjusts triggering thresholds internally. The advantage of the triggering algorithm is a better understanding of steady-state activity. The disadvantage is that large databases are created for relatively short monitoring periods. On a case-by-case basis, this is not a problem. However, for long-term studies that incorporate hundreds of monitors, the handling of such large databases is not feasible.

Voltage and Current Monitors

Voltage and current monitors are typically more expensive than voltage-only devices because the number of monitor channels is typically twice that of voltage-only recording devices. The addition of current as a parameter allows for calculation of power parameters. Just like the voltage-only monitors, voltage and current monitors come packaged for portable, hardwired, and meter-based uses. The portable units are more expensive because of the requirement for clamp-on current transformers (CTs) and the need of the electronics to be packaged in a rugged enclosure to survive daily bumps and vibrations associated with portable use. These potable devices are also usually designed to work in larger temperature extremes than some hardwired devices. Hardwired devices for permanent installations are lower cost than their portable counterparts, not requiring expensive packaging associated with portable equipment. Hardwired monitors can use permanently installed CTs, which are usually less expensive than clamp-on CTs. Because meter-based devices have CTs built in and external connections are minimized, their overall costs are less than their portable or hardwired counterparts. When current information is required, the meter-based monitor device should be the best package to apply for customer PQ monitoring. Use of a meter-based monitor or electronic revenue meter with PQ functionality built in and a modem connection for remote data collection should provide the most data for the lowest cost.

Transducer Requirements

Transducers are devices required to convert line voltages and currents to the low-level signals that a monitor can safely measure. For customer monitoring, most monitors are capable of recording voltages directly without the need for transducers. Therefore, potential transformers (PTs) do not need to be discussed. If a monitor is selected with current-recording capability, then CTs will be necessary. As discussed previously, portable devices use clamp-on CTs. Clamp-on CTs are designed to open like a spring-loaded clothes pin to allow a current-carrying conductor to be clamped. More permanent-type CTs might be installed where hardwired monitors are employed. These CTs may be "split core" or "donut" style CTs. The split core CT has a portion of the core that may be mechanically opened to allow the CT to be positioned around a conductor. The advantage of the split core CT is the ability to install it without breaking conductor terminations. A donut CT is shaped like a donut, requiring a conductor to be place through the hole in the middle of the CT. While donut CTs are typically less expensive then bar CTs, donut CTs do require the circuit conductor to be temporary removed to insert through the CT. Where meter-based monitoring is used, the CTs are an integral part of the meter-base extension or the revenue meter and special installation considerations are not necessary.

The quality of the current connections can affect the recorded data. The following are three common problems when using clamp-on CTs:

- The conductor or bus bar is not properly positioned within the clamped area.
- The two split-core ends do not make solid contact.
- The wrong type or numbers of conductors are enclosed within the CT.

Included in this last item is the improper polarity problem where a CT is positioned backwards or the CT polarity is incorrect.

"CT specifications typically assume that the conductor or bus bar is positioned dead center within the clamped area. Any other location will incur some accuracy error. If the clamp ends do not mate solidly, then the resulting gap between the ends will also introduce error into the measurement. Unlike the error from positioning, however, this gap error may also affect recorded waveforms. Whenever multiple conductors are being measured, care should be taken to ensure that no return conductors are also being measured. This would cancel some or all of the magnetic field of the conductor being measured, thus changing the reading.

"When selecting CT's for power monitoring application, the following four points should be considered:

- "The accuracy of the readings (a combination of CT and instrument accuracy)
- "Phase shift if the instrument is capable of providing measurements of phase relationships
- "Response and phase shift over the measurement bandwidth

- "The crest factor capability"[18]

Frequency-response characteristics of the selected CTs are a primary concern when performing PQ measurements. Careful consideration to sizing is also a primary concern to take advantage of the full resolution of the instrument without clipping the measured signal. Standard metering-class CTs are generally adequate for frequencies up to 20 kHz (phase error may start to become significant before this). For higher frequencies, window CTs with a high turns ratio (doughnut, split core, bar type, and clamp-on) should be used.

Additional desirable attributes of CTs include:

- Large turns ratio (for example, 2000:5 or greater).
- Window-type CTs are preferred.
- Small remnant flux (for example, ≤10% of core saturation value).
- Large core area. The more steel that is used in the core, the better the frequency response of the CT.

Selection of the proper CT current rating and turns ratio depends on the measurement objective. If fault or inrush currents are of concern, the CT must be sized in the range of 20 to 30 times the normal load current. This will result in low resolution of the load currents and inability to accurately characterize load current harmonics. For long-term customer monitoring, CTs should be selected to accurately characterize load currents. This permits evaluation of load response to system voltage variation and if measured, accurate calculation of load current harmonics.

Power Supply Requirements

Instrument power is often taken from one of the phase voltages heing monitored. This makes it undesirable to protect the input line from transient overvoltages, because operation of a surge-protective device corrupts the monitored signal. Instead, the power supply should be designed to withstand transients defined by IEEE Std. C62.41, class A and B waveforms. The peak voltages for class A and B waveforms should be 6 kV and 1 kV, respectively. Higher magnitudes should cause a fuse in the power supply to blow. If the monitor at a particular location experiences frequent fuse operations, it may be necessary to apply surge protection to the power supply input. If this is the case, then power supply power should be obtained from a separate source, which is often difficult to achieve. If a separate source is not practical, a constant-voltage transformer may be used between the signal voltage and the power supply to absorb the surge and provide isolation from the signal voltage.

The instrument should be provided a battery back-up power supply to provide monitoring during long-duration variations and control monitor shutdown during power interruptions. The back-up battery should provide power for a minimum of 15 minutes. When an interruption occurs that is longer than the run duration of the back-up power supply, the monitor should automatically

[18] IEEE Std 1159 – 1995, Page 31

restart when power is restored and a text event should be recorded indicating when the power was restored and the duration of the interruption. Memory of recorded data should exceed one year.

For revenue meters with PQ monitoring capabilities, the maximum power supply is restricted to 40 W. If the PQ monitoring portion of the revenue meter requires greater than 40 W to operate, an external power supply is required. Therefore, the functionality of the PQ portion of a revenue meter may be limited by the 40-W power supply limitation.

Environmental Concerns

Ten years ago, PQ monitors designed for outside use were very rare if not nonexistent. Then monitoring outside required providing a NEMA type-4 enclosure with air-conditioning to protect the monitor from the elements. Today, many monitors are designed for outside use. Typically, these monitors are built into a NEMA type-4 enclosure, which is resistant to rain, dust, ice, and corrosion. Operating in the outdoor elements requires the device to operate in severe temperature and humidity ranges. The region of the country that the monitors are to operate in may determine the maximum and minimum operating temperatures for the device. A customer PQ monitoring project may involve all regions of the country. Therefore, the largest possible operating temperature range should be considered. A temperature range of –40 °C to +65 °C (-40 °F to 145 °F) should be a reasonable temperature specification. The operating humidity for the monitors should be 0 to 95 %, non-condensing. Table 9-4 summarizes the operating conditions for a revenue meter with PQ monitoring capabilities.

Table 9-4
Meter Operating Conditions

Temperature	-40 °C to +85 °C
Humidity	0% to 95%, non-condensing
Frequency	57 to 63 hertz (60-Hz model)
Power supply voltage input	The power supply can be connected internally to the voltage phases or brought out through an optional external auxiliary power source.
Optional auxiliary power supply input	AC or DC supply, 100 V to 240 V +25, -20%

Communication Concerns

All monitoring projects require a method of extracting the data from the monitor to a computer for further evaluation. Historically, the first method of electronic data extraction from a monitor was through diskettes. This method was followed by a direct connection to a computer through an RS-232 serial cable. More recently, there are fiber-optic interfaces that serve the same purpose. Relying on manual downloading of monitored data is labor-intensive and only as reliable as the person doing the work. For these reasons, the capability to transmit monitor data

from a remote monitor to a central computer is a necessity for long-term monitoring projects. Analog phone lines and modems have been used for years to remotely transfer data to and from monitors and computers. Many monitoring devices today can be supplied with an internal modem for this purpose. Cell phones have been used less successfully for monitor data transfer. Typically, cellular data transfers require a very slow baud rate to ensure data integrity. However, when this is the only means of communication, it becomes feasible. Some monitors today provide LAN-based connections and TCP/IP connections to allow data transfer directly over the Internet. Even with all these new technologies available, we shouldn't forget about the old reliable RS-232 connection. The RS-232 can be used as an optional communication means should one of these internal technologies fail. An RS-232 connection may be used to connect to an external telephone modem, cellular modem, or broadband cable modem.

Media availability may also influence the method of communication. Some monitors are designed to call the central computer when there is a need to transfer data. This allows for sharing of a phone line with the customer phone without the customer experiencing an incoming call from the central computer. When a monitor does not have a call-out option, then it is advisable that a separate telephone line be used to contact the monitor from the central computer. Some areas where cable TV is well established provide broadband Internet service through cable modems. While still fairly new to the monitoring industry, cable modems might be used to increase data transfer rates and cut down on telephone long distance charges. Broadband connections might be better applied where the monitors can be connected directly to the Internet with TCP/IP addressing capability.

Monitor Installation Practices

A major concern during PQ monitoring project is the installation of the PQ monitors. When utilities conduct PQ projects on their systems, monitor installation is not a great concern. The utility can place the monitors on the utility poles or in the substation without the involvement of customers. However, when performing a customer PQ survey, the monitors will need to be installed as close to the customer as possible. Therefore, the total cooperation of the customer will be required.

Site Preparation

The length of the PQ monitoring project will be determined during the site-selection phase of the project. To characterize PQ, a minimum of one year's worth of monitoring will be required at each location. Therefore, it will be necessary to install the PQ monitor permanently at the residence.

As with any monitoring project, safety and reliability of the monitoring installation will be of the utmost concern. Both national and local codes will need to be addressed before the PQ monitor can be installed.

In general, the PQ monitor must be installed in a tamper-proof enclosure. Some manufacturers offer a lockable enclosure. Other manufacturers of PQ monitors offer a package that can be

installed directly into the meter base. By having a PQ monitor that can be installed in the meter base:

- The installation time can be reduced
- The need for potential transformers (PTs) and current transformers (CTs) can be eliminated
- The need for external power can be eliminated
- The need to mount the PQ monitor can be eliminated

Other PQ monitors will require that they be mounted to the residence in some fashion. If mounting the PQ monitor to the residence is not acceptable, a stand-alone mounting bracket will need to be developed to allow the PQ monitor to be mounted near the energy meter.

Other considerations like environmental concerns need to be addressed. Unless the PQ monitor is mounted within the residence, which is highly unlikely, the enclosure for the PQ monitor must be weather-tight. This means that weather-tight conduit will need to be run from the PQ monitor to the meter base.

Communications

The most reliable and economical method for configuring and retrieving data from the monitoring instruments is through a telephone line. A majority of commercially available PQ instruments have the ability to be configured and interrogated using telephone line.

When conducting utility PQ monitoring projects, most substations have telephone lines installed for use when lineman or other utility personnel are working in the substation. These telephone lines can typically be used for monitoring projects because the instrument needs to be contacted only once or twice a day. If required, a telephone-line sharing device can be installed.

A telephone line-sharing device allows the monitoring instrument and the telephone to be connected to the same telephone line. When a call comes into the facility, the line-sharing device answers the call. It then waits for instructions, tones from the calling device, to route the call. If no instructions are received, it defaults to ring the telephone. These line-sharing devices can be configured to work with telephone answering devices (TADs), modems, and facsimile machines.

In the case of customer PQ monitoring, it may be necessary to install a second dedicated telephone line for the instrument. Although the PQ monitor is typically contacted once a day, this contact occurs late in the evening or early in the morning. If the PQ monitor shared the line with the customer's telephone, the line would ring when the call was made. This would be a nuisance to the customer. A line-sharing device could be used, but they have not proven very reliable in the past.

The cost for a second telephone line is typically in the range of $20 to $30 per month. Depending on the PQ monitor chosen for the project, there would not be any other charges for the telephone line. If the PQ monitor selected for the project was capable of calling the master station to alert during an event, long-distance charges could apply.

Monitor Connections

One concern that many utility engineers have is the connection of the PQ monitor to the circuit under test. Voltage connections typically do not require any special considerations. To measure current, however, the circuit must be interrupted to install CTs.

Voltage Connections

The voltage connections can be accomplished with lug connectors or alligator clips. However, alligator clips are intended for temporary installations. Given the duration of typical PQ monitoring projects, lug connectors are the preferred method of securing the potential leads. Depending on the practices of the individual utility, the potential leads may be connected without de-energizing the circuit, although it is recommended that the circuit be de-energized before connecting the PQ monitor.

The voltage levels on distribution systems and in customer facilities can typically exceed 1000 V RMS. All commercially available PQ monitors are capable of measuring 600 V RMS. Therefore, PTs will be required for most monitoring projects unless measurements are performed on the low side of a customer transformer.

Current Connections

The current connections can be accomplished with window or "doughnut" style CTs. These types of CTs require that the circuit be de-energized and the current-carrying conductor be run through the opening of the CT. Window-type CTs can be physically large, and a separate enclosure to house the CTs may be required.

Clamp-on CTs are available for measuring current. These types of CTs have a split core. The iron in the CT is split and can be opened, placed around the conductor, and closed again to complete the circuit. The use of this type of CT does not require the installer to disconnect any wiring. It is recommended that the circuit be de-energized before the installation of the CTs. Clamp-on CTs can be physically large, and a separate enclosure to house the CTs may be required. Figure 9-14 shows several examples of commercially available clamp-on CTs.

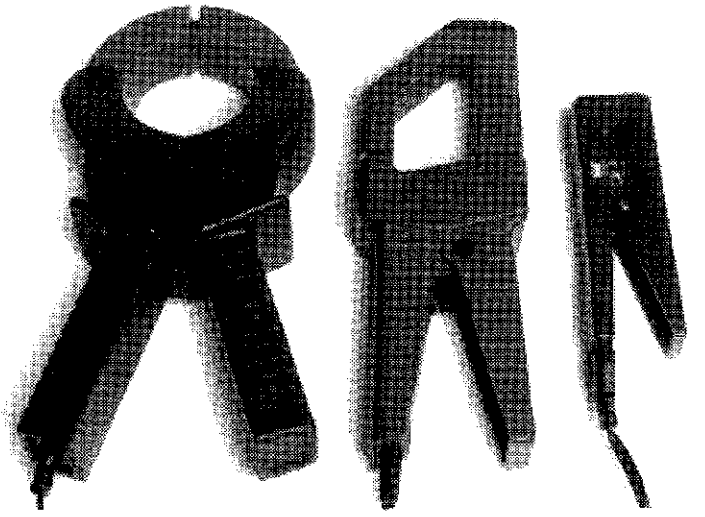


Figure 9-14
Examples of Common Clamp-on Current Transformers That are Commercially Available

Frequency Response

One concern when using any type of transducer is the response of that transducer. In other words, how well does the transducer pass the signal that it is measuring? The frequency response of window-type CTs is well documented in an EPRI report on the Distribution Power Quality Project (see Figure 9-15). For more information on the frequency response of PTs and CTs, please see EPRI TR-103208, *A Guide to Monitoring Distribution Power Quality.*

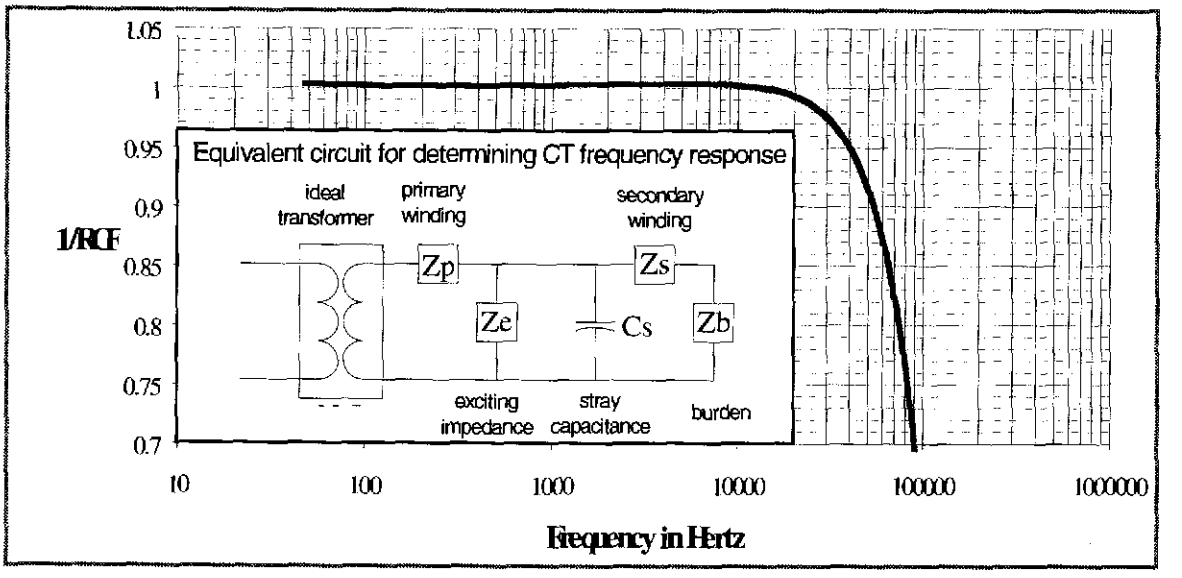


Figure 9-15
Frequency Response of Window Type Current Transformer (Taken From EPRI Report TR-103208[19])

The frequency response of clamp-on CTS can vary widely. Depending on the use of the CT, its response may only be up to 1 kHZ. Table 9-5 gives the frequency range of some commercially available clamp-on CTs. These values are specific to one manufacturer.

Table 9-5
Example Frequency Ranges of Commercially Available Clamp on Current Transformers

Model	Turns Ratio	Current Range (A)	Frequency Range (Hz)
MN105	1000:1	2 to 150	45 to 1000
MN170	100:1	2 to 75	45 to 1000
MN185	1000:1	0.05 to 150	45 to 10k
MD302	1000:1	4 to 500	48 to 1000
MD304	100:1	1 to 600	48 to 1000
SD601	1000:1	0.05 to 1000	30 to 50k
JM800	1000:1	1 to 1000	30 to 5000
JM830	3000:1	1 to 3000	30 to 5000

[19] *A Guide to Monitoring Distribution Power Quality, Phase 1,* EPRI, Palo Alto, CA: April 1994. EPRI TR-103208.

Monitor Thresholds

After the PQ monitor has been installed, it must be configured. The thresholds set in the instrument will determine when, how long, and how often data will be collected by the PQ monitoring instrument. Manufacturers of PQ monitors use two methods for setting thresholds.

- User-selectable thresholds
- Automatic thresholds

User-Selectable Thresholds

Instruments that require the user to set the thresholds assume that the user knows what data or information is needed. When performing a benchmarking or predictive survey, these instruments are very suitable. By setting the thresholds, the user can select the types of events that are of interest. This also allows the user to manage the memory of the instrument.

When performing benchmarking PQ monitoring, it is advantageous to have all the monitors in the study configured with the same thresholds. This allows data from each monitor and system to be compared with other monitors and systems. Correlations between system-wide events are easily identified when all monitors are configured the same.

Thresholds are typically identified at the beginning of the monitoring project by the project team and participating utilities. IEEE and ANSI standards are used as a starting point for setting the thresholds. Once the initial thresholds have been set and several months worth of data have been collected, the thresholds may be changed as deemed necessary by the project team. In some instances, it may be necessary to change thresholds because of false triggering or system changes.

Automatic Thresholds

With the advances in neural network and fuzzy logic systems, manufacturers of PQ monitors have been able to use this technology to develop instruments that require little or no interaction to characterize PQ. These type instruments constantly monitor and keep track of what "normal" PQ levels are and adjust their setting accordingly. This type of technology allows the instrument to capture all events that occur. When the instrument memory becomes full, it starts to overwrite less severe events with more severe events.

For any monitoring project, it is recommended that a PQ monitoring device that allows user-selectable thresholds be used. This will allow the project team to customize the monitoring project to fit the needs of the utilities and customers participating in the project.

Data Collection

The data-collection process for any type of monitoring project is just as critical as the data itself. Data integrity is very important to the success of a monitoring project. If the monitoring project is to be statistically valid, a traceable path of all data must be maintained.

The data-collection process not only involves downloading measurement data from instruments, but also the collection of system configuration, system parameters, system events (utility operations), and customer loads.

Data-Collection System

It is common for a utility to purchase and maintain a master station to perform all the measurement functions during the monitoring project. The master station will be used to set up and interrogate the monitoring instruments.

Because of the nature of the computer industry, the specific master station system should be specified when the project has been finalized. For budgeting purposes, a minimum system is often specified as part of the project during the planning phase. Once the project is approved and funded, a system is purchased with approximately the same cost, but often with greater capabilities.

The master station must be capable of running the software that communicates with the PQ instruments. The master station must also be capable of housing the monitoring data collected during the course of the project. Table 9-6 illustrates example specifications for a master-station computer.

Table 9-6
Example Master Station Computer Specifications

Master Station Computer
Pentium-III microprocessor
512-K, Level 2 cache
256 MB of RAM
Option 1: Two 20-GB Hard Drives - SCSI arranged in a mirrored set (software RAID 1) will need a PCI SCSI card Option 2: Three 20-GB Hard Drives - arranged as RAID 5 using a Hardware RAID Card
The above is for high availability. Selection depends on budget with the first option being the easiest and least expensive to configure. The hardware RAID gives performance and fault tolerance benefits.
Fast Ethernet network card

Windows NT 4.0 Workstation

Monitoring systems with more than 20 PQ monitors require a separate download computer. A separate download computer allows for hourly downloads, which proves invaluable when customers require immediate access to their data. The separate download computer also allows the master station to perform various tasks like data characterization, data analysis, and report writing. Table 9-7 lists the minimum requirements for a download computer.

Table 9-7
Example Download Computer Specifications

Download Computer Specification
Pentium III
256K, Level 2 Cache
256 MB RAM
10- to 20-GB Hard Drive
At least one 16-port or two 8-port DigiBoard multi port serial interface (PCI)
Rockwell-based external modems

Measurement Data

All data collected from power quality monitors is usually stored in a common location. This simplifies the data analysis functions by eliminating the need to search for data in several storage locations.

Power quality data is usually collected from the monitors on a nightly basis using one of the following methods:

- Traditional telephone
- Cellular telephone
- Ethernet

Utility System Events

A record of all system operations and events on the system should be maintained. The date, time, and location of the event should be recorded in a database that is maintained by the utility. This data can be used to correlate measurements and events on the system. The following is a list of important system parameters that should be tracked at the utility level:

- Customer concerns

- Equipment failures
- All switching operations (whether normal or abnormal)
- Weather-related events (lightning, ice, tornados, and so on)
- Protective device operations (substation breaker, reclosers, fuses, and so on)
- Transmission level events

Customer Data

Certain customer data is usually required for a power quality monitoring. This includes specific data about the loads in the customers facility as well as the effects, if any, that PQ events had on the customer equipment.

Customer System

Once the site-selection process has been completed, information on the distribution system and customer loads can be collected. The type of service and system used to feed the customer can have a dramatic impact on the PQ levels within the facility. Whether the customer is served from overhead triplex or an underground cable will affect the susceptibility to lightning. Table 9-8 illustrates the data required for each customer monitoring site. This table is geared toward use with residential customers. Similar data would be collected for industrial and commercial customers.

Table 9-8
Required Customer Information

Data Required	Typical Response
Transformer size	10, 15, 25, kVA, and so on
Number of customers served from transformer	Specific number
Service type	Overhead or underground
Service drop length	Specific number
Service drop wire size	Specific number
Service size	Specific number (for example, 200 A)
Three-phase or single-phase circuit serving transformer	Three or single phase
Number and type of protective devices between customer and substation	Recloser, fuses, and other

Customer Loads

Not only does the type of service used for the customer affect the PQ levels in the residence, but the types of loads in the residence can have an effect, or be affected by, the power PQ of the system serving the residence. In order to more accurately characterize the effects of power quality on customers, information on the types of loads in the facilities will be required. Table 9-9 lists the required information concerning customer loads. This table is geared toward residential monitoring projects.

Table 9-9
Required Load Information

Data Required	Typical Response
Type of heating	Electric or gas
If electric, what type	Heat pump, resistive, and so on
If heat pump, what type	Air to air or geothermal
Other large electric loads	Welder, compressor, and so on
Water heater type	Electric or gas
Electronic loads	Computer, TV, and so on
Surge suppression	Yes or no
If surge suppression, what type	Whole house, outlet, power strip
UPS on computer	Yes or no
If UPS, what type	Stand-by, on-line, and so on

Disturbance Recording

It is very helpful for customers to fill out disturbance-recording forms whenever loads are disrupted within their facility. This information is critical to the correlation between system events (utility), weather-related events, and customer-related events (for example, faults within the facility). One option is to provide a booklet of disturbance-recording forms that are to be filled out whenever a PQ event is experienced as shown in Figure 9-16. This form is designed to be used with residential customers. A similar form could be developed for commercial and industrial customers.

Residential Disturbance Recording Form

Date: _____

Time: _____

Name: _____

Address: _____

_____

Phone: _____

Description: _____

_____

_____

_____

What happened before event? _____

_____

_____

_____

Equipment: _____

_____

Manufacturer: _____

_____

Ratings: 120 Volt _____ 240 Volt _____

Figure 9-16
Example Customer Disturbance Recording Form

Data Collection Interval

The data collection interval depends entirely on the amount of data that the PQ monitor can hold, how often the downloads are verified, and the need for the monitoring data. If the monitor can store up to three-days worth or PQ data, then it is sufficient to download data from the PQ monitors once every 24 hours. This assumes that the downloads are verified on a daily basis and that the PQ monitoring data is not needed immediately after an event is recorded.

If data is required immediately after an event occurs, there are two basic options. The first is to use a PQ monitor that calls back to the master station. When this call back is initiated, the master station or download computer will download the PQ data from the instrument. The second option is to have a PQ monitor that is polled at a regular basis, less than 5 minutes. Current technology allows users to setup polling intervals in the seconds time frame.

For the most PQ monitoring projects, it is unlikely that the data will be needed immediately after an event occurs. Therefore, polling the PQ monitors once or twice a day should be sufficient. If data is needed immediately, the attendant of the master station or download computer can initiate a forced download.

10
COST OF OUTAGES AND POWER QUALITY EVENTS

Background

One of the really difficult problems faced by those responsible for distribution planning is to decide how far they are justified in increasing the investment to improve service reliability. Therefore, power system planners need to determine an adequate balance between costs and reliability for satisfying the predicted load. One of the critical input data for developing a framework of cost-benefit evaluation is to quantify the value of reliability to customers. Such a cost-benefit analysis constitutes the focal point of the *value-based reliability planning*. Value-based planning provides a rational and consistent framework for answering the fundamental economic question of how much reliability is adequate from the customer perspective and where a utility should spend its reliability dollars to optimize efficiency and satisfy customers' electricity requirements at the lowest cost. Costs to customers associated with varying levels of service reliability are significant factors that cannot be ignored. Explicit considerations of these customer-interruption costs in developing supply-reliability targets and in evaluating alternative proposals for network upgrade, maintenance, and system design must, therefore, be included in system planning and design process. This section of the report provides some results of customer valuation of reliability and outlines a methodology that can be used by the Philippine distribution utilities to develop their own framework.

Methodologies For Assessing Outage Costs

Various methodologies exist for gathering data on customer outage costs. Most methods do not apply equally well to residential and commercial/industrial customers. Therefore, a study that samples all of these customers often uses multiple methods. Below are the most common types of survey and analysis methods for different customer classes:

Survey Methods

- Contingent valuation methods
- Contingent ranking methods
- Indirect cost approaches
- Direct cost approaches

Analytical Methods

- Wage rate proxy
- Value of service in the home
- Case studies of blackouts
- Backup generator proxy
- Output-to-electricity-consumption ratio
- Relation of gross national product (GNP) to energy use

Table 10-1 summarizes the pros and cons of the different approaches.

Table 10-1
Summary of Alternative Types of Surveys and Analysis Methods

Contingent Valuation Methods	
Description	Survey-based assessment of willingness to pay (WTP) to avoid an interruption or willingness to accept (WTA) compensation for an interruption
Customers	Residential
Pros	Allows assessment of residential customers
Cons	General survey weaknesses. Plus customers are notoriously poor at providing numerical estimates of their actual willingness to pay when faced with real choices
Contingent Ranking Methods	
Description	Customer value functions are inferred from customer's choice or ranking of a series of outage options, each accompanied by a rate increase or decrease. WTP and WTA can be inferred from a technique called conjoint analysis applied to these rankings.
Customers	Residential
Pros	Very accurate results because of close duplication of actual customer choice procedure
Cons	Can involve large amounts of data if many attributes are considered
Indirect Cost Approaches	
Description	Evaluation of costs by identifying adequate substitutes for reliable power, such as insurance policies to compensate for interruption effects
Customers	Mostly residential
Pros	Addresses preferences rather than straight monetary effects. Better than direct cost approach when intangible values are present

Cons	Can be very unreliable. Error is introduced by non-monetary features of the substitutes (for example, payment terms and conditions of insurance policies). Typically, a large number of aggregate assumptions need to be made
Direct Cost Approaches	
Description	Respondent evaluates costs associated with particular outage scenarios
Customers	Commercial/Industrial (sometimes used with residential, but with limited success)
Pros	Provides consistent results where outage costs are quantifiable
Cons	Does not apply well to residential sector, where impacts are less tangible, or to any situation in which monetary losses are not directly identifiable
Wage Rate Proxy	
Description	Equates lost leisure time because of outages with wages earned
Customers	Residential
Pros	Simple. Eliminates problems inherent in survey methods. Some research suggests wage rate is a valid proxy
Cons	Does not address time-of-day differences. Likely to overestimate outage costs. Does not reflect actual customers' needs
Value of Service in the Home	
Description	Values residential outage costs by the market value of services lost in the event of a power outage
Customers	Residential
Pros	
Cons	Assessing market value of home services requires many assumptions. Assumes services lost because of outage cannot easily be made up at another time
Case Studies of Blackouts	
Description	Measures the direct and indirect economic costs of a large-scale blackout, including costs related to looting, rioting, and arson
Customers	All
Pros	Provides a concrete basis for assessment
Cons	Information is only relevant to the incident and not easily generalized
Backup Generator Proxy	

Description	Assumes customers will purchase backup generators until the cost meets the marginal cost of unsupplied power
Customers	Commercial/Industrial
Pros	
Cons	Provide only an upper bound on outage costs for customers who do not purchase backup generation. Relies on many assumptions: average generator cost, depreciation rates, generator lifetime, fuel costs, and interruption hours per year
Output-to-Electricity-Consumption Ratio	
Description	Output per kWh of electricity consumed provides an upper bound on outage costs
Customers	Commercial/Industrial
Pros	
Cons	Assumes no substitution for electricity with other factors of production. Ignores damaged equipment costs. Assumes production cannot be made up after power resumes
Relation of GNP to Electricity Use	
Description	Relates gross national product (GNP) to use of electricity
Customers	Commercial/Industrial
Pros	Data is publicly available
Cons	Assessments are only available on a large, geo-political scale

Synthesis of Outage Cost Data

The following methodology was used by EPRI PEAC to develop a range of outage cost for different customer segments for the eastern region of the United States:

- Reviewed statistically valid outage cost studies reported in journals, reports, and papers (See Appendix A for a bibliography).
- Used consumer price index (http://www.aier.org/cgi-bin/colcalculator.cgi) supplied by the U.S. Department of Labor to adjust outage cost data in the individual surveys to current year U.S. dollars.
- Used a cost-of-living index to translate each survey result to take into account geographical variance.
- Excluded the minimum and maximum values as outliers and take the average of the rest to come up with the revised numbers.

The results of this analysis are shown in Table 10-2 for residential, commercial, small industrial (<5 MVA) and large industrial (>5 MVA) customer segments:

Table 10-2
Outage Costs for Eastern Region of the United States

Customer Segments	First Hour Cost (USD/kWh)	Additional Hour (USD/kWh)	Momentary Interruption $/kW
Residential	1.17	3.21	0.04
Commercial	16.62	13.71	2.15
Small Industrial (<5 MVA)	15.18	11.04	3.56
Large Industrial (>5 MVA)	7.62	2.38	5.14

Differences Within Each Customer Segment

It is widely known that even within a customer segment (for example, large industrial) the outage cost may vary significantly from one type of industry to another. While the survey-based data of Table 10-2 may be used to represent the average for a customer class, the survey results in Figure 10-1 show how the cost of outage varies among different categories of customers within a segment.

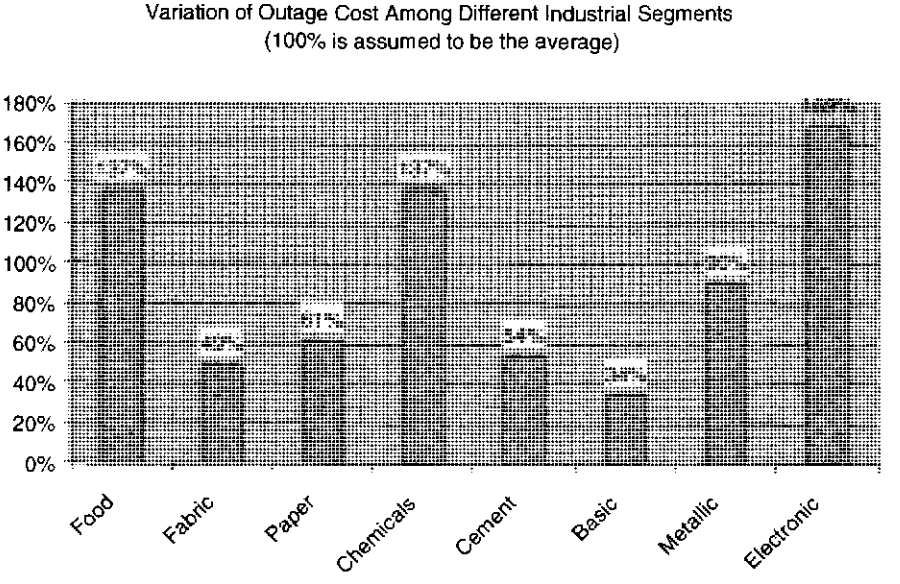


Figure 10-1
Variation of Outage Cost Among Different Industrial Customers

Scheduled Versus Unscheduled Outage

If customers are provided early warning for a scheduled outage, then the cost of outage reduces considerably. Figure 10-2 shows the average percentage reduction in outage cost based on the analysis of the survey results from the literature.

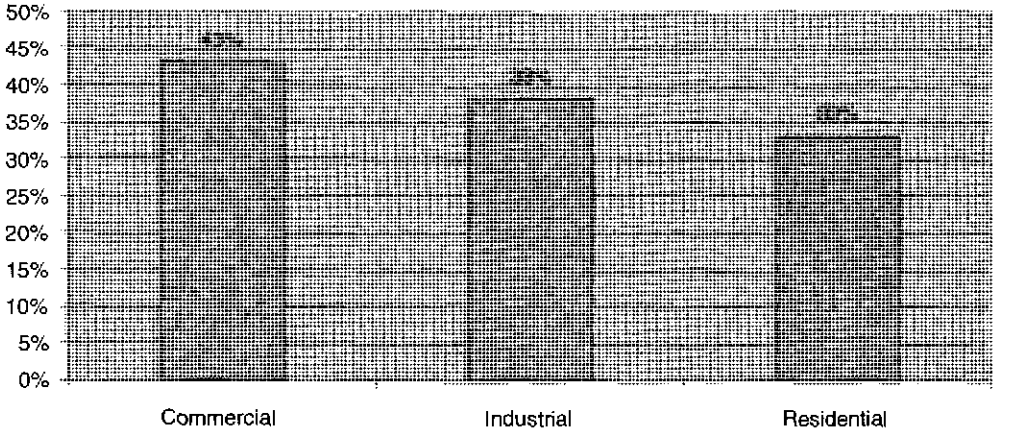


Figure 10-2
Reduction in Outage Cost for Scheduled Outages (Customers Receive Early Warning)

Applying This Data in the Context of Philippines

The outage cost data presented in this section is relevant in the context of the U.S. economy specifically for the eastern region. Clearly, the most appropriate method will be to conduct a statistically valid survey among customers in Philippines. This type of survey is generally used for determining cost of an outage. Appendix B (entitled "Commercial and Industrial Sample Form for Outage-Cost Survey") and Appendix C (entitled "Residential Sample Form for Outage-Cost Survey") provides sample questionnaires that are used as a survey instruments, and if needed, the participating utilities may want to conduct on their own or hire a third party to conduct such a survey to quantify the outage cost from the Philippine perspective. Appendix D (entitled "Sample Design for Outage Cost Survey") provides guidance in the design of a statistically valid sample. Appendix E (entitled "Economic Evaluation Using Methodology Outlined in IEEE 1346") provides a tutorial in designing sample surveys from a large population.

However, in the meanwhile if the utilities would like to use results of the survey data in this report the following recommendation could be made to translate the data in the context of Philippines:

- Adjust the cost of an outage based on a multiplier (Suggest using 0.086 based on World Bank 2000 data for economic indicators) that reflects the difference in hourly wage rates in the United States and in Philippines. This method will exaggerate the difference because while lost labor is a factor especially for commercial and industrial

outage cost, it is not the only factor. Another method could be to assume a certain percent of outage cost to be fixed and apply the multiplying factor for the remaining portion of the cost. Table 10-3 shows the range of outage cost based on data presented in Table 10-2 and assuming that 100% of the outage cost can be translated based on the labor rate multiplier and using a currency rate of 1 USD = 51.7 PHP

- Adjust the cost of an outage based on the ratio of Gross National Product (GNP) and electricity consumption (kWh). Based on 1996 country statistics from the World Bank, the ratio of GNP/kWh consumption for the United States was approximately 2.5 and for Philippines 2.6. While the United States had a much higher GNP/capita, it also had a much higher kWh electricity consumption per capita. If this metric is used, then there is hardly any change in the outage cost data as presented in Table 10-3 from the United States to Philippines. It appears that the GNP relationship to kWh as a measure of outage cost does not truly reflect the differences in outage cost in the United States and in Philippines.

Table 10-3
Calculated Outage Costs for Philippines

Customer Segment	First Hour Cost (PHP/kWh)	Additional Hour (PHP/kWh)	Momentary Interruption (PHP/kW)
Residential	5–33	14–90	0.18–1.12
Commercial	74–467	61–385	9.6–60
Small Industrial (<5 MVA)	68–426	49–310	16–100
Large Industrial (>5 MVA)	34–214	11–67	23–144

Customer Valuation of Power Quality

Power quality (PQ) problems can have an impact on the business activities of industrial and commercial customers, and the quantification of that impact is imperative to the successful implementation of a premium power strategy. Determining the cost of PQ problem is often a daunting task because the cost of a particular problem is unique to the end user experiencing the problem and the situation in which it is experienced and, to some extent, is a function of a firm's accounting practices.

There has been much research on the subject of customer cost of outages that relates to the reliability of power. Identifying industry-specific cost for PQ-related disruptions are even more daunting. Very limited survey results are available in the literature that relates to PQ cost. In addition, the subjective nature of PQ-related process downtime makes it even more difficult to gauge this quantitatively in a survey-based approach.

Methodology to Evaluate Industry-Specific Cost of Power Quality

To evaluate industry-specific cost of PQ events, the project team relied on data that was obtained from specific PQ investigations that have been conducted by EPRI PEAC over the last several years. In addition to this data source, the project team also reviewed technical papers that describe the results of PQ investigations for specific customers and includes data on financial impact to the customer. This approach was used to obtain industry-specific cost data for the continuous-process manufacturing (CPM) sector. This sector includes manufacturing facilities that continuously feed raw materials, often at high temperatures, through an industrial process. Specific industries include paper, chemicals, petroleum, rubber and plastic, stone, clay and glass, and primary metals.

This methodology was not applied to ascertain PQ cost for the digital economy (DE) sector. This sector includes firms that rely heavily on data storage and retrieval, data processing, and research and development operations. Specific industries include telecommunications, data storage and retrieval services (including collocation facilities or internet hotels), biotechnology, electronics manufacturing, and the financial industry. These industry segments, in almost every case, use extensive on-site power-protection equipment for minimizing PQ-related and reliability-related process downtime. An indirect way to gauge the cost of PQ and reliability for this industry class is to use the proxy method. The proxy method relies on data that quantifies how much these customer segments are investing for PQ and reliability protection. This method provides a quantitative metric to evaluate the PQ and reliability cost to the digital economy sector.

Continuous-Process Manufacturing (CPM)

Figure 10-3 shows the cost of PQ to specific industries within the CPM sector, normalized to the total demand in kW. The source for the cost data was obtained as mentioned in the previous paragraph from individual PQ investigations that were conducted for specific customers within the CPM sector. The costs represent the best estimate of the PQ cost for the specific customers that were evaluated as part of the PQ investigation. While understanding that costs for any specific customer will depend on the unique characteristics of that customer, these cost numbers provide a range of "typical" costs for the specific industry segment that can be used for macro-level planning purposes.

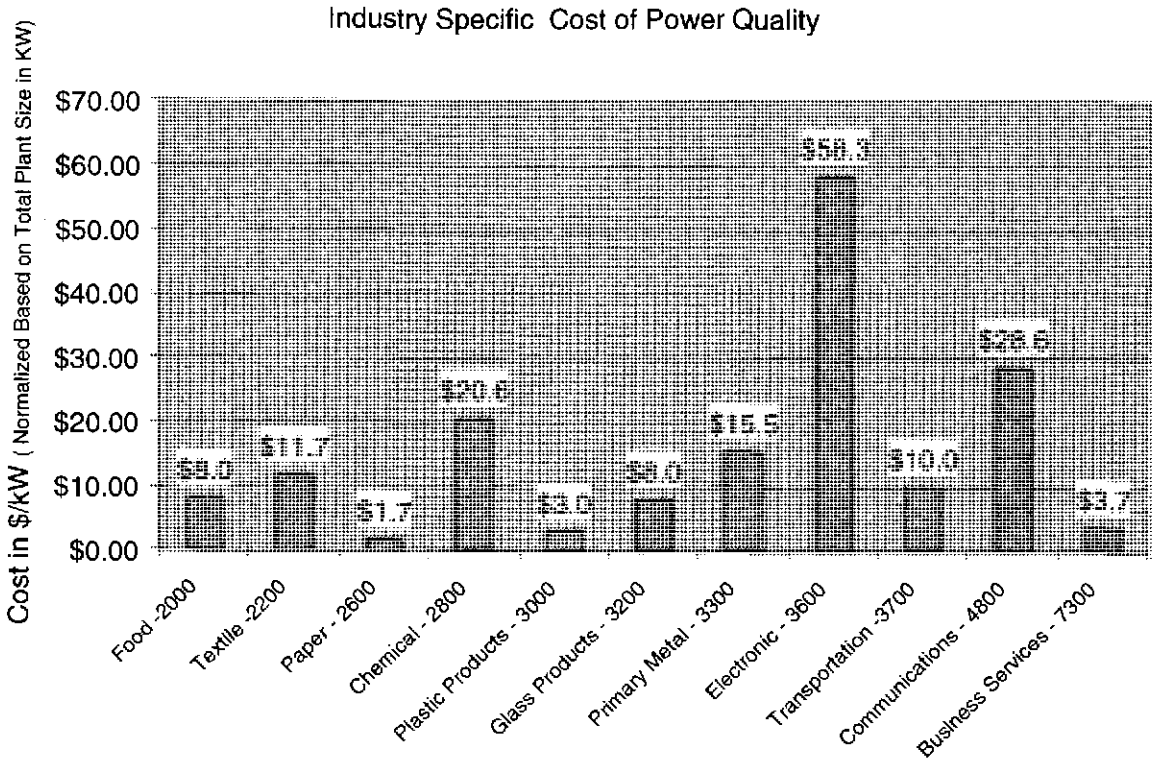


Figure 10-3
Industry-Specific Cost of Power Quality for Continuous-Process Manufacturing Sector

Description of Power Quality Cost Information

The following pages, shows information (if available) regarding different aspects of PQ cost for individual customers within several segments of industries that broadly represent the CPM sector. A description of the table entries follows:

SIC Code ..... Four-digit code of the primary industry category

Industry Category ..... Description of the primary industry category

Industry Description ..... Description of the specific industry category

Load Size (kW) ..... Peak demand (in kW)

Cost of PQ/Event ..... Financial impact of PQ-related process downtime

Normalized Cost ($/kW): ..... Total cost divided by the total demand

Cost Elements: ..... Cost elements that were used to derive the total cost per PQ event. They include:

- Downtime
- Production loss
- Damage raw material
- Damage equipment
- Lost opportunity
- Miscellaneous

Downtime (hours) ..... Time (in hours) it takes for restoring the process if it has been affected by a PQ event such as a voltage sag or a momentary interruption.

Confidence in Data ..... A qualitative (very high, high, medium, low) representation of the accuracy of the cost data based on the level of detail of information that was available from each source.

Table 10-4
Industry-Specific Cost of Power Quality for Continuous-Manufacturing Process (CPM) Industries

SIC Code	Industry Category	Industry Description	Load Size (kW)	Cost of PQ/Event ($)	Normalized Cost ($/kW)	Cost Elements	Downtime (Hours)	Confidence in Data
2000	Food & kindred products	Dairy product	5,000	40,000	8.00	1, 2, 3, 5	3	High
2200	Textile mill products	Synthetic fiber plant operates a continuous process to produce plastic strips for carpet backing	1,000	15,000	15.00	1, 2	11	Very High
		Carpet backing manufacturer	2,500	15,000	6.00	1, 2, 3, 4		High
					14.00			Low
2600	Paper & allied products	Newsprint paper and pulp mill	100,000	56,000	0.56	1, 2	4	Very High
		Newsprint paper and pulp mill	100,000	190,000	1.90	1, 2, 4	7	Very High
		Paper & packaging mill	4,000	15,000	3.75			Low
		Paper mill	31,000				1.15	High
		Newsprint mill	30,000	12,000	0.40			High
2800	Chemical and allied products	Polymer product	5,000	160,000	32.00	1, 2		High
		Vinyl acetate monomer product manufacturer	5,000	75,000	15.00			Medium
		Intermediate chemical products for paints, plastics, and various other industries	3,000	110,000	36.67			Medium

		Plant makes vinyl chloride, ethylene, chlorine	105,000	1,000,000	9.52			Medium
					10.00			Low

Table 10-4 (Continued)
Industry-Specific Cost of Power Quality for Continuous-Manufacturing Process (CPM) Industries

SIC Code	Industry Category	Industry Description	Load Size (kW)	Cost of PQ/Event ($)	Normalized Cost ($/kW)	Cost Elements	Downtime (Hours)	Confidence in Data
3000	Rubber/misc. plastic products	Polymer-based insulators	2,000	18,000	9.00	1, 2, 3		High
		Producer of vinyl/plastic furniture	4,000	7,500	1.88			Low
		Plastic container	3,500	1,000	0.29	2		Low
		Manufactures polyethylene pellets from liquefied petroleum		10,000				Medium
		Plastic injection presses		2,500			1	Low
		Plastic extrusion process	3,000	10,000	3.33			High
		Plastic extrusion process	6,000	10,000	1.67			Medium
		Manufacturer of high-speed, high bandwidth cables for video, data and other communication applications		29,000				Medium

		Plastic bag manufacturing	6,000	10,000	1.67			Low
3200	Stone, clay, glass & concrete products	Glass manufacturing	2,500	20,000	8.00			High

Table 10-4 (Continued)
Industry-Specific Cost of Power Quality for Continuous-Manufacturing Process (CPM) Industries

SIC Code	Industry Category	Industry Description	Load Size (kW)	Cost of PQ/Event ($)	Normalized Cost ($/kW)	Cost Elements	Downtime (Hours)	Confidence in Data
3300	Primary metal industries	Wire manufacturer	2,000	17,000	8.50	1, 2, 3	2	
		Metal casting	16,000	500,000	31.25			Low
		Large precision rollers for steel rolling mills	500	10,000	20.00			Low
		Stainless steel manufacturer	2,500	5,500	2.20			Low
3600	Electronic, electrical equipment & components	Semiconductor fabrication plant	10,000	700,000	70.00	1, 2, 3		High
		Semiconductor fabrication plant	30,000	1,400,000	46.67			Low
3700	Transportation equipment	Manufacturer of aircraft engine blades	10,000	100,000	10.00	1, 2, 3		High
4800	Communications	Broadcast facility	3,500	100,000	28.57	1, 5	0.5	High
7300	Business services	Commercial office building	6,000	22,000	3.67		0.5	Medium

Power Quality Cost in European Union

The European Copper Institute (www.cda.org.uk) with the support of the European Community and International Copper Association, Ltd., conducted a project to determine the cost of PQ in European Union countries. Table 10-5 shows the representative costs of voltage sags to some industry classes.

Table 10-5
Cost of Voltage Sags in European Union

Industry	Typical Financial Loss per Event ($)
Semiconductor production	3,800,000
Financial trading	6,000,000 per hour
Computer center	750,000
Telecommunications	30,000 per minute
Steel works	350,000
Glass industry	250,000

Some of the key findings of the project were:

- For continuous processes, such as papermaking, the effect of a voltage sag is just as serious as a complete blackout, with the same clean-up costs, raw material losses, and lost production.
- For computer-based operations, the time taken to reboot a large number of workstations and recover pending transactions and unsaved documents can take several hours.
- The semiconductor industry is particularly vulnerable because wafers require two dozen or so manufacturing stages to be completed over several days. If a wafer is spoiled towards the end of the process all the value of the work done is lost. The rate of development in semiconductors is now so fast, competition so intense, and product life cycles so short that the loss of product is a major concern not only to the suppliers but also to their customers who cannot build and ship their own products.

Determining Individual Customer Power Quality Costs

Appendix E (entitled "Economic Evaluation Using Methodology Outlined in IEEE 1346") explains a method to evaluate and analyze the financial impact of PQ. This method is based on the methodology outlined in IEEE 1346, *Recommended Practice for Evaluating Electric Power System Compatibility with Electronic Process Equipment.*

It is intended to be generic in coverage and does not necessarily represent any particular type of business. Although generic guidance is provided, the user should very carefully ensure that all applicable costs particular to the user's specific operation are identified if the analysis is to provide meaningful results. The method presented in Appendix E is intended to identify general costs associated with PQ disruptions and is not intended to function as an accounting system.

11
PLAN TO MEET REQUIREMENTS IN THE PHILIPPINE DISTRIBUTION CODE

The purpose of this chapter is to provide an assessment of the investments required to meet the reliability and power quality requirements set forth in the Philippine Distribution Code. This chapter focuses on the definite requirements prescribed in the Code. The discussion will be separated into requirements along with possible techniques for compliance, and budgetary estimate for compliance.

Philippine Distribution Code Requirements

The Philippine Distribution Code contains many requirements for Distributors. Many of the requirements will have significant impact on the design and operation of the distribution systems of Philippine electric utilities. The following are the requirements most directly related to reliability and power quality.

RMS Voltage Related Requirements

Many of the quality requirements in the Code relate to the quality of the voltage supplied to customers. These requirements could be the most expensive to meet.

Article 3.2.3.4 states "The Distributor shall ensure that no Undervoltage or Overvoltage is present at the Connection Point of any User during normal operating conditions." The Code defines an Undervoltage as a voltage variation lasting longer than 1 minute where the RMS magnitude of the voltage is less than 90 percent of nominal. Similarly, an Overvoltage is a voltage variation lasting longer than 1 minute where the RMS magnitude of the voltage is greater than 110 percent of nominal.

The Philippine Grid Code, which defines requirements for transmission utilities, allows the transmission supplier to provide a voltage level between 95% and 105% at the connection point to a Distributor. This allows the Distributor only a 5% voltage drop from the connection point with the grid to the point of service to a customer. The drop through the station power transformer can exceed 5% at full load. Adjusting the manual tap on a station power transformer can make up this voltage drop, but could lead to overvoltage conditions during periods of light loading. The result of Article 3.2.3.4 is the necessity of installing some form of automatic voltage regulation equipment on every distribution bus or feeder. Station power transformers with On Load Tap Changing capabilities (often referred to as LTC in North America) can provide the required voltage regulation in most cases. However, Article 3.2.5.2 sets

requirements for voltage unbalance that may force the use of per-phase Automatic Voltage Regulators (AVR).

Article 3.2.5.2 states "The maximum Voltage Unbalance at the Connection Point of any User, excluding the Voltage Unbalance passed on from the Grid, shall not exceed 2.5 percent during normal operating conditions." The Philippine Grid Code allows a voltage unbalance from the grid of up to 1 percent. Discerning what portion of the unbalance is from the Grid when a customer complains about high voltage unbalance could be quite difficult. It is likely the customer will consider 2.5% to be the limit, regardless of Grid levels.

Voltage unbalance is not corrected by LTC transformers. An LTC transformer adjusts the voltage levels on all three phases simultaneously and equally. Automatic Voltage Regulators, AVR, are the only practical means of ensuring compliance with the unbalance requirements. Proper load balancing can help reduce the number of AVRs required on a feeder, but cannot guarantee compliance under all normal loading conditions. It is possible, with proper load balancing, that a single set of three AVRs could be applied to the medium voltage bus of a distribution station to maintain proper voltage balance. However, long feeders may require additional AVR installations to maintain proper load balance at locations remote from the feeder source.

Article 3.2.3.4 states "The Distributor shall ensure that the Distribution System has sufficient capacity so that Voltage Sags when starting large induction motors will not adversely affect any User facilities or Equipment." This requires the Distributor to have sufficient short circuit capacity at the User facility so that voltage sags resulting from motor starting are minimized. Section 5.3.3 specifies that a Distribution Impact Study be performed for customers wishing to connect to the distribution system. It further states that the proposed connection "shall not result in the Degradation of the Distribution System." While not specifically stated in either Article, the Distributor will need to determine the maximum motor size that can be started across the line, along with the maximum motor size that can be started with reduced voltage starting. SynerGEE has the ability to perform this analysis.

Harmonics and Flicker Requirements

Article 3.2.4.4 limits the THD (total harmonic distortion) of the voltage at any User System to less than 5%. Similarly, Article 3.2.4.5 limits the TDD (total demand distortion) of the current to less than 5%. Section 5.2.5.2 states that the "User shall ensure that its System shall not cause Harmonics in the Distribution System to exceed the limits specified in Section 3.2.4." The Distributor has very little control over the level of harmonics in the distribution system other than to enforce the limits set forth for Users. If User TDD current is maintained below 5%, the distribution system voltage THD should be less than 5% except in cases of extremely low fault availability (high system impedance). It is also possible for a resonance to occur at a distribution capacitor bank that could cause a higher than normal voltage THD. These are relatively rare and can be handled on a case-by-case basis.

Article 3.2.6.4 states "The Flicker Severity at the Connection Point of any User shall not exceed 1.0 unit for short term and 0.8 units for long term." Article 5.2.7.2 specifies that it is the User's responsibility to ensure that his system does not cause flicker on the distribution system. Again, the Distributor has very little control over the level of flicker caused by Users, other than to enforce the limits set forth in the Code. Section 7.9.1 outlines Testing Requirements that include measuring flicker and harmonics. While meters that do an adequate job of measuring harmonics are relatively common, there are few meters to choose from that can measure flicker. Those that are available are quite expensive, starting at PHP1,000,000.

Reliability Requirements

Section 3.3.2 identifies the distribution Reliability indices that Distribution Utilities shall use: System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Momentary Average Interruption Frequency Index (MAIFI). These indices are in common use by utilities in North America also.

Article 3.3.4.2 states "the ERC (Energy Regulatory Commission) shall set the performance targets for Distribution System after due notice and hearing." Section 9.4.1 requires the Distributor to provide 5 years of historical performance data in the form of the three required indices. Section 9.4.2 sets the initial limit for the reliability indices at the mean of the Distributor's 5 years of historical performance data for each index with upper and lower limits of one standard deviation. This will cause problems with one index in particular: MAIFI. The lack of reclosing on most of the feeders of the client Distributors has resulted in artificially low MAIFI numbers while greatly increasing the values of SAIFI and SAIDI. Implementing reclosing, along with other coordination changes, will significantly lower SAIFI and SAIDI but will increase MAIFI. This tradeoff will need to be explained to the ERC.

System Efficiency Standards

Section 3.4.1 defines three classes of system losses: Technical Loss, Non-Technical Loss, and Administrative Loss. Section 3.4.2 indicates that the ERC shall set a cap on the level of System Losses that the Distributor can pass on to its End-Users. Article 3.4.3.3 states "the Distributor shall correct feeder and substation feeder bus Reactive Power Demand to a level, which economically reduce feeder loss." This will reduce the amount of Technical Loss. Perhaps the most efficient means of reducing Technical Loss is the installation of switched capacitor banks on the distribution feeder. The controls for such banks can be programmed to provide the appropriate reactive compensation to optimize the losses of the feeder.

Compliance Techniques and Costs

Section 9.7.2 requires Distributors to provide plans for compliance with all technical specifications, performance standards, and financial capability standards. These plans must provide for compliance in three years. Again, this discussion is focusing on power quality and reliability requirements. The initial reliability targets are based on past performance and a plan

that shows gradual improvements in the area of reliability would be the most cost effective approach. The voltage requirements are predefined and could be the most expensive to meet.

The remainder of this chapter was removed due to considerations of proprietary data.

12
EVALUATION OF CURRENT GIS AND RECOMMENDATIONS ON AN OUTAGE MANAGEMENT SYSTEM

GIS Based Outage Management System

Current Practice

The Dispatch Center receives all customer calls regarding power outages and/or wires down. The dispatchers have to look at circuit maps (if they are updated and available) to determine which device had failed based on the location of the customers who had reported the outage. Once these calls are analyzed a crew is dispatched to restore power. This is a time-consuming and cumbersome process.

VECO needs to:

- Reduce the number of trouble calls requiring manual processing
- Ensure that customers would not receive a busy signal
- Provide customers with an estimated time for power restoration
- Speed up power restoration by automating processes (automatic analysis of calls and automatic fault prediction leading to better information getting to the crew faster)

Essentially VECO needs a GIS-based outage management system. The GIS system is the first building block of an automated outage management system. The minimum capabilities of such a system are described in the list below.

- Must handle customer calls through an interactive voice response system (by matching trouble calls to outages already reported.
- Must allow for after hours dispatch of trouble calls.
- Must automate the process of predicting failed devices (based on the locations of the incoming trouble calls and the circuit information from the Enterprise GIS database)
- Must enable remote offices to update and print trouble orders over the Intranet
- Must integrate with other systems at VECO (such as the mobile dispatch system used by line crews)

The dispatch system currently allows line crews to receive and update trouble orders in their line trucks via radio. An interface can be built to allow communications with wireless, handheld devices. With a GIS-based system in place, line crews could update trouble orders even when they are away from their line trucks. They can be alerted immediately with details of the urgency, location, and type of problem.

Investment

The investment in technology is minimal, mostly the acquisition of an off the shelf GIS system (VECO already has the other required software.) GE Smallworld is recommended, requirements as below.

- Smallworld GIS™
- Oracle 8i™
- Microsoft Windows NT™
- Microsoft Visual C™
- Microsoft Visual Basic™
- Microsoft Active Server Pages™
- Microsoft NT Server Terminal Server Edition™
- IBM MQ Series™

Benefit

A GIS-based outage management system can be expected to enable VECO to process three times as many trouble calls as the present system, in the same amount of time.

Outage Management and Integration

Impact on Reliability

Outage management systems, as well as distribution management systems, have a direct influence on power delivery system reliability. This is even more important in a deregulated environment where utilities are accountable to reliability indices that are maintained on a standard and regular basis. This is not only a matter of customer relations, but a competitive factor with major users who may have a choice and a political issue as reliability-performance measures are increasingly scrutinized by public utility commissions.

Integration with SCADA

One of the issues facing potential new users of outage management software is the 'stand-alone' versus the 'integrated' nature of the application. Unlike many other utility applications, outage management is totally reliant on external linkages to customer information system, distribution monitoring systems (DMS)/SCADA systems and service dispatching-crew scheduling operations. The need to combine elements of the real-time SCADA system with transaction-oriented and event-driven information systems is critical. The need for the outage management system to be geographically (GIS) driven is a core consideration.

Implementation

Successful implementation of an outage management system needs strong interdepartmental coordination. No single business unit can be solely responsible. A coordinated inter-department project team, led by the IT or engineering department, seems to be the best way to undertake these enterprise-type programs and projects.

Enterprise Wide System

An enterprise application integration technology should be adapted. Then, different business processes for outages from different sources can be properly described and their role in the overall outage management system clearly identified. All the processes need to be included. The available tools to the System Operator (SO) are listed, and the improvements in system performance are highlighted.

Re-Engineering – Towards an Enterprise Wide System

To re-engineer all the IT and operating systems, from billing systems to outage management systems, into an Enterprise Wide System is a daunting task. This enormous effort is accomplished by acquiring some new applications and combining them with existing databases and programs. These extend beyond engineering and operations to financials, materials management, customer care, and work management components.

Components

There are multiple departments/divisions in the power utility dealing with outages. During an outage lifecycle, these entities are performing various tasks. Some of them are:

- Call-taker or Customer Service Representative enters the order
- Order processing in the Customer Information System
- System operator groups and studies the order, generates the switching procedures and identifies the required repair works
- Dispatcher receives the work orders and assign them to field crew

- Field crew obtains clearance, drives to the site, performs the required work and then reports the status to the dispatcher/supervisor
- Dispatcher/supervisor sorts the orders and reports them to CIS
- Customer service representative calls back customer

Different automation systems can be used to cover some of these steps. Daily operations and departmental responsibilities are necessary for the overall management structure, but these "islands" need to be interconnected and their activities automated to the extent that data can be usefully shared.

A typical enterprise environment consists of many legacy and new applications, component adapters and enterprise servers. An enterprise server hosts a common message bus. This server may also include data translation and data transformation software. Data translation and transformation software makes applications independent from each other.

Outage Related Business Processes

Outage related business processes are divided into the three major categories: trouble call, SCADA-recognized outages, and planned outages. These categories are described in the following text.

Trouble Call Business Process

A customer calls through interactive voice response (IVR) or customer service representative (CSR) to reach the customer information system. After filtering the calls for repeated calls or known outages (if any), a call notification or trouble ticket (TT) is issued and sent to OMS. OMS either groups the new TT with existing outage records by using DMS applications or creates a new order request (OR).

Provisions are provided to the SO to receive the alarm and associate it to the OR and the circuit diagram (including the geographic location). OMS provides the probable cause of outage by identifying the upstream disconnecting device(s) that might be opened/tripped.

The fully integrated OMS/SCADA/DMS system provides a user friendly and flexible environment to the SO to create switching procedures that isolate the faulty segment and restore the power. Also, simulation tools are available to study the effects of generated switching procedures on the network.

The SO creates the job requests necessary to rectify the outage (including job types/codes). Each job request, with the coordination of the work management system (WMS) through Plant Maintenance, is translated to a work order that is sent to a mobile data system. The dispatcher schedules the work and assigns field crew to perform the job requested by the SO.

Crew ID, work status, and estimated time to repair are part of the data provided by DMS to OMS.

The SO monitors the status of each work order, creates new job requests if necessary, and closes the OR when satisfied. OMS automatically sends messages to CIS whenever there is a change in the energization status of parts of the network, estimated time to repair, or OR status. CIS is capable of initiating callbacks (if necessary/required) based on the information provided by OMS.

- **Business Process for SCADA-Recognized Outages**

The trouble call business process is designed in such a way that it can cover SCADA recognized outages as well. The only difference is in the creation of the OR. After SCADA identified de-energized segment(s) in the network, OMS creates an OR and sends the message to CIS identifying the de-energized transformers. Afterwards receiving new trouble calls are treated as in the previous business process.

- **Business Process for Planned Outage**

The planned outage business process is divided in two phases: planning, and execution. In the planning phase, the WMS identifies the list of transformers to be maintained for specific period and sends the message to OMS via plant maintenance. The SO studies the list by using DMS applications and, if necessary, modify the list and generate the switching procedures to perform the maintenance work.

OMS sends the message back to the plant manager with the modifications. Affected customers will be notified by letters or called sometime prior to the execution phase.

In the execution phase, the switching procedure(s) will be performed by the SO through SCADA, or field crew similar to the trouble call business process. The rest of the activities will be similar to the trouble call business process.

Generation of Data for Reliability Indices

The main features provided by these business processes in general, and the outage management capabilities in particular, as they relate to reliability indices, can be summarized as follows:

- Receive trouble calls and identify the problem area; group by area
- Monitor response to the outage during its lifecycle
- Determine remedial actions; generate switching procedures
- Perform part of switching procedures via SCADA (if possible)
- Generate job requests necessary for isolation, repair, or restoration
- Close the operations report

- Calculate and update the reliability indices
- Generate reports for current or closed outages in different levels of the network in different time frames

Integration

The integrated OMS/SCADA/DMS performs a number of tasks automatically after receiving the trouble calls (or SCADA events): grouping the call, associating the call to an existing operations report or creating a new one, and identifying the de-energized sections and probable problem area.

The outage management system should provide a user-friendly environment for the system operator to create the switching procedures and job requests and send them with a minimal number of steps. It should provide the system operator the capability to monitor the overall outage situation and all activities around it with minimal intervention/operation. Consequently, the system operator should be able to handle multiple operations reports simultaneously during crisis events, such as major storms. An automated outage management system, within an integrated enterprise distribution management system, provides for the dissemination of data and a sorting mechanism to assist the system operator in managing the operations reports while respecting the integrity of the overall data collecting process that meets the criteria to calculate reliability indices (data in terms of customers affected, lost power, etc.).

Recommendation

Making use of the integration tools to create an efficient, timely, full integration with the enterprise. Placing integration processing in a central location also reduces future maintenance costs. This strategy permits future changes to the system that can be handled in the middleware rather than rewriting point-to-point interfaces. The net result for the SO is to work with an integrated system that provides a full picture of all tasks relevant to outages with minimal work.

Implementation Process

GIS integration with outage management systems is the most important contribution that IT can make to the improvement of operations as they relate to outages and customers, and thus, directly impact the reliability indices.

Everything that utilities do operationally can be related one way or another to GIS. It can be the central, unifying management tool in the utility. Data and operational activities can be related to geography, from going out and repairing and maintaining the system to serving customers. Integrating GIS to outage and work management bring it a step further into enterprise management systems. For starters, outage management is the most important as relates to reliability indices.

Building Blocks

If outages can be displayed on top of a map of the physical geography and facilities layout of a utility's electric system, getting to the places that need to be "fixed" in an outage can take place much more efficiently. Some of these integrated systems now are providing on-screen map displays that include:

- The current status of the distribution network
- The location of facilities and work crews
- The distribution of trouble calls
- Outage locations and predicted further outages
- The ability to "drag-and-drop" work crews automatically generating the necessary work orders.

If these maps are then distributed digitally to work crews in the field, via mobile data terminals, the ability to enhance customer service is obvious. In fact, the utility may even to response to outages before the customer even knows there is one. Telephone systems can be programmed to identify people who call in to report an outage and respond that the company already knows about the outage and give an approximate time when it will be restored.

Restoration of an outage is handled digitally in several steps that include:

- A customer outage call is directed to the OMS.
- The OMS identifies the location by cross-reference with the CIS
- That location then is plotted via the AM/FM/GIS system
- The OMS predicts additional outage locations based on the AM/FM connectivity model
- Crews are electronically dispatched based on availability and geographic locations via dispatchers who have access to the map overlays showing the outage
- Crews, with mobile computers provide real-time updates back through the OMS, which then can be passed back to customers.

Some systems can handle an average of 60%--sometimes as high as 90%--of all trouble calls automatically, without intervention by a "human" customer service representative.

Process

The goal of enterprise management is to provide business processes which mainly use spatial information--primarily technical processes--to provide them with integrated IT solutions. The processes selected to be fully integrated with maps are:

- Engineering design
- Outage management

- Maintenance
- Network management
- Sales & marketing

The utility's own, highly qualified IT professionals can be used to "co-develop" the enterprise distribution system with their expertise in legacy subsystems. Operations personnel can be involved, contributing their in-depth knowledge of the local distribution system. Sales and marketing can be included in the project; they need to be able to track customers by their specific locations as a part of the marketing effort.

Basically, outage management involves more than 80 "elementary processes" that go into receiving trouble calls and repairing the system, etc., taking the system all the way to the field (with the full GIS eventually residing on laptop computers).

All road maps should be stored completely in the GIS and all complex information throughout the system should eventually be available on the field laptops.

A significant portion of the operations and maintenance budget should be spent as part of the implementation of the integration of geospatial information in all the selected processes.

Good data is the key to successful implementation; this includes engineering data on conductivity, phasing, customers, transformers and feeder configuration. This may involve some distribution design engineering to:

- Modify the model build code
- Modify its data model and data
- Modify structure of switch gear internals
- Modify digitizing standards for UG conductors
- Modify UG conductors to conform in the GIS to new standards

These complex reconfigurations of how the systems work together to portray outages graphically. The integration management process should offer guidelines for reconciling these various areas.

Vendors

The integration of GIS with outage management is a relatively recent development so the vendors and their alliances are evolving.

GIS systems tended to be stand-alone, primarily for the use of engineers. As a result, several companies developed outage management systems separately from GIS. These systems tend to

work with call centers and models of the electric system to track and sometimes predict the extent of outages. But overlaying that on maps has given GIS companies such as GE Smallworld, Intergraph, and ESRI new impetus toward becoming integrated into mainstream utility operations. As a result, both GE Smallworld and Integraph now have their own outage management modules that plug into the GIS. ESRI, the largest of the three, plugs in an outage module from Miner & Miner, a close partner with which ESRI has worked for the last decade or so.

Companies that have specialized in outage management, but not GIS, notably CES International, M3i, ABB Automation-Utilities, Siemens, and others now are stressing the ability of their systems to be integrated with underlying GIS.

Recommendation

Because of its well developed, and cost competitive GIS foundation, Smallworld, and the ability to integrate multiple subsystems from legacy systems, and an integrated AM/FM/GIS with outage management and virtually all other IT systems, the GE Smallworld PowerOn System is recommended for an Enterprise Distribution Management System.

Major Issues

GIS mapping is a major issue. There is a digital map of the distribution network, but pole numbers need to be recorded and poles matched to customers. Also, the database of system interruptions needs to be related to poles. There is much work to be done before the existing data can be utilized for GIS, outage management, and other support services that contribute to improving reliability.

The Autocad map is the only map presently prepared, it needs to be converted to GIS. To this end, a modular, highly functional GIS system needs to be purchased and installed. GENMAP, currently used by VECO is inadequate, insufficient, and out of date. ESRI is a possible candidate, but quite expensive. The challenge is the conversion of the data from Autocad, and the interface with the CIS, at a minimum. These are the high-priority objectives.

In consideration of the presently available data and needs, VECO should consider one of two alternate routes for GIS. One is to work with DLPC, building on the relationships in the Philippines, to develop a custom system based on the one in use at DLPC. If the scope is limited to constructing a GIS database, this might be cost effective. The other alternative is to work with the SmallWorld portion only of the GE Smallworld PowerOn distribution management system. This would be a start with a leading edge system. This would allow more opportunities for additional functionality in the future. The cost of the Smallworld GIS is probably competitive with ESRI and other vendors. Joint purchasing or cost sharing with cooperatives should be considered, as the system is capable of handling substantially more data than VECO would enter. However, it must be kept in mind that the conversion is a prerequisite.

The Smallworld GIS is sufficiently comprehensive to meet VECO's present and future needs. This is shown in the schematic below in Figure 12-1.

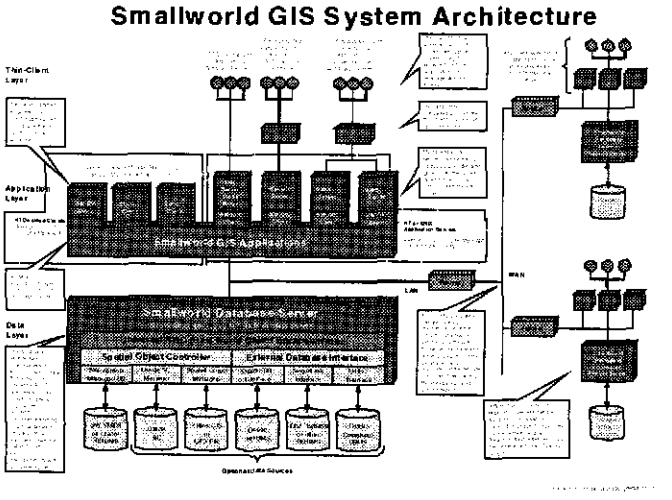


Figure 12-1
GE Smallworld GIS System Architecture

Most importantly any GIS system would require the dedication of personnel within VECO for data entry and database maintenance and management. The value of the investment in a GIS system diminishes quickly when the data is not properly maintained.

Once a GIS system is installed and the data entered, it should be integrated with the CIS operations reports on outages. These data files must then be maintained regularly.

The GIS should be viewed as an umbrella for multiple IT applications, as well as the basic building block. Indeed, it is an ideal integration vehicle for many operational systems. AM/FM would be an ideal addition. And, eventually the SynerGEE software could be utilized with the AM/FM/GIS so that the network models could be created from completed data (graphical and data base) within the AM/FM/GIS. This becomes an even more useful tool for decision makers when linked with SCADA, Trouble Call, and Work Order systems. Again, the emphasis is on GIS as the first step.

AM/FM System

Description

An AM/FM system that is GIS-based can be designed to provide VECO with an important tool to improve productivity, reduce the cost of constructing, operating and maintaining distribution facilities, and contribute to the GIS system that supports a more efficient and effective outage management system. In this way, an AM/FM system that is GIS-based can contribute to the responsiveness of the outage management system and thus positively impact reliability indices.

Implementation

The most important part of the implementation of AM/FM systems is the conversion of existing digitized and paper map data. System development and data conversion activities can take many months and must be well planned. They must be supported by sufficient resources to complete the task continuously from start to finish without gaps when information can become outdated, and data conversion procedures and practices change and become inconsistent. Consistency and continuity are important.

Further, maintenance procedures must be put in place to insure the integrity of the data at high standards. This is best accomplished by the dedication of a stable workforce of experienced staff with a well-managed plan, within strict control costs.

Additional factors to consider during implementation are system development support (including software upgrades), user training, and the structuring of the data conversion activities themselves.

Suggested Requirements

- Smallworld GIS™
- Microsoft Windows NT™
- IBM MQ Series™
- Safe Software FME™

Additional Resources

This is not to underestimate the complexity and magnitude of planning and implementing an AM/FM Project. The quality of the database is critical. Vendor expertise should be tapped to help solve data plotting problems, or external data entry firms can be used.

The integration of GIS with an outage management system must wait until an operational GIS system is in place. When VECO has GIS/AM.FM systems developed to a high standard, it will be ready for integration with an outage management system at a similar level of functionality.

At that time, VECO will be in a position to consider moving to an Enterprise Management System that includes a world-class outage management system.

The Enterprise Management System offered by GE Smallworld PowerOn distribution management system would be an ideal candidate when the individual components are in place in VECO.

POWERON CONFIGURATION

The scope of the PowerOn system, and its integration capabilities, is shown in the schematic below in Figure 12-2.

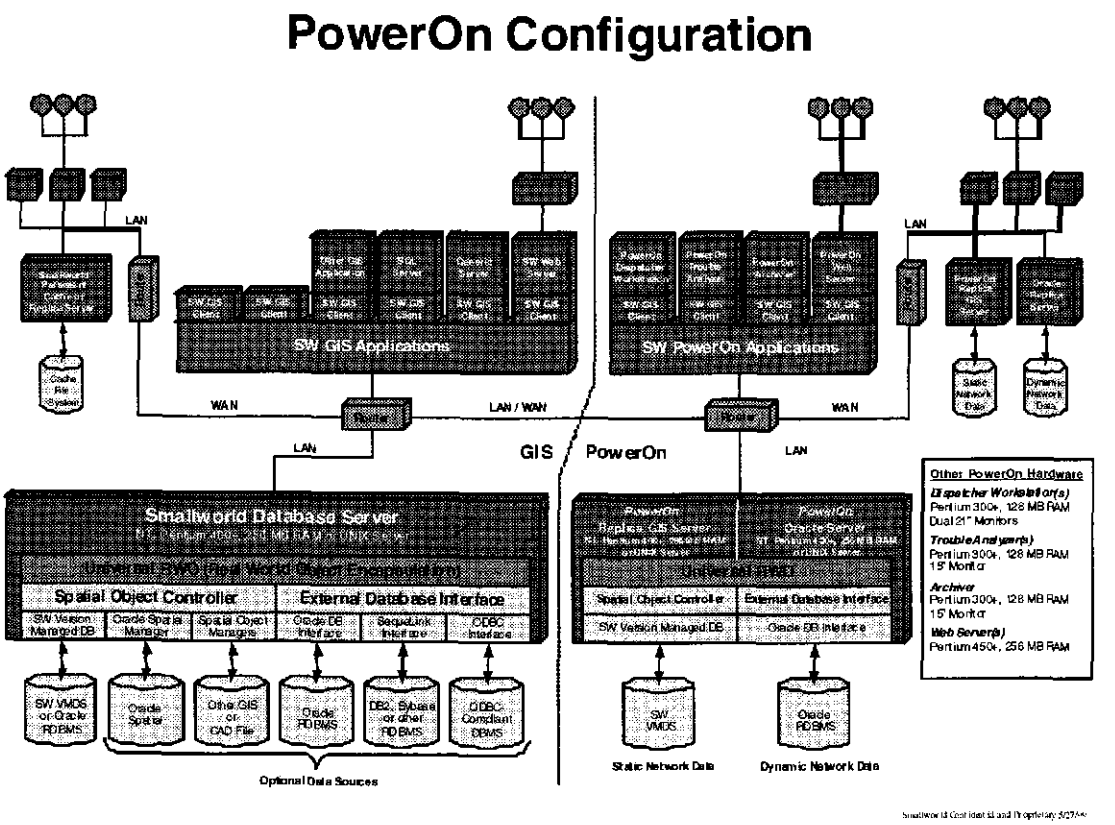


Figure 12-2
GE PowerOn Configuration

EPRI Strategic Asset Optimization

The three utilities should consider purchasing from EPRI the Strategic Asset Optimization program (Appendix I). It is a proprietary tool that can be used to show which service territories

are constrained and are limited to support additional load, as well as those regions where capacity is available to support additional load.

Using utility maps (based on geographical information systems), the regions where the distribution system is at or near its capacity to supply power are identified. All of this information is displayed on an easy to read map, which shows the locations of regions served by an individual substation. Feeders that are at or near capacity can be identified, as well as customers who are additional load on the feeder. It can also be used to determine when the same substation has excess capacity and can serve additional customers.

All the large industrial and commercial customers who are responsible for most of the power delivered by the feeder are identified on the GIS map. Using knowledge of these customers, the SAO can determine their load requirements and usage patterns within the context of the distribution system.

The SAO approach can also be used to identify future requirements for showing the growth in load over a period of time. As service territories grow, excess capacity of feeders is consumed, the distribution circuit is at or near capacity and can longer be relied on.

Based on Geographic Information Systems (GIS), EPRI has built custom information systems that interact with a utility's AM/FM, Customer Information System, Outage Management System, and other internal and external databases to enhance both strategic planning and operations. The models enable the utility to integrate data from various sources and visualize the relationships between the data sets. The resulting models are used to simulate new customer locations, analyze circuit and system reliability, investigate distributed generation deployment, plan customer marketing and conservation programs, and track operational issues such as distribution system maintenance. In the course of this GIS work, we have worked with all major platforms including ESRI, Intergraph, SmallWorld, and other proprietary systems.

13
EVALUATION OF USE OF FIBER COMMUNICATIONS

Presently VECO's communications does not provide sufficient back-up routes and thus redundancy. There is a need for back-up communications and an increase in reliability and capacity. This would be accomplished by a dedicated communications system.

Once a dedicated communications system is in place, it can be linked to neighboring utilities, and possibly RTUs in substations at cooperatives adjacent to the distribution system. Thus real time information can be provided on equipment status.

A fiber optic backbone would support the wide area network (WAN) throughout the company for communication between the central office and remote locations, including substations. This will be increasingly important when the SCADA is fully deployed.

A LAN/WAN is already installed and in operation at VECO. The internet is used for email and communication with some vendors and major customers. A dedicated communications system would enable the extension of the internet at low cost throughout the company.

In weighing the alternatives for a dedicated communications system, it is recommended that VECO proceed to implement a project to install a system wide fiber optic network. Much of the existing network at the various locations could be connected to this backbone at minimal cost, while providing significant increases in capacity and reliability.

The fiber optic network should be installed along with the Line Current Differential Relay system that is being considered for system protection on the 69 KV lines. These lines cover the Cebu City service territory and eight substations. This would support much of the internal telecommunications requirements and other data communications requirements. CISCO wireless communications links should be considered as a cost-effective solution for the remaining links to substations.

14
INTEGRATION OF WORK MANAGEMENT SYSTEM WITH ACCOUNTING OPERATIONS REPORTS

The work management system is not integrated with accounting operations. This is recognized by both the IT and Accounting Departments.

The work management system needs to be designed to interface with the Enterprise Management System that will eventually be the primary IT tool for VECO.

For the present, the IT department has sufficient well-trained personnel to perform the necessary integration of reports. This should receive a high priority in the IT Department's work plan.

15
SCADA EXTENSION

Two substations cannot be automated due to old, obsolete breakers. The replacement of these breakers is necessary as part of the system reliability upgrades being recommended in this reliability study. Once these two substations are automated, the same SCADA devices that are deployed at the other 11 substations should be installed, and linked to the central system.

16
AMR RECOMMENDATIONS

VECO has indicated interest in using automated meter reading (AMR) for key customers. AMR ensures accurate and timely meter reading data. Also, many AMR equipped meters have power quality monitoring capabilities that can be useful in handling customer complaints. The power quality monitoring features can also be used to verify compliance with a premium power contract if one exists.

Types of AMR

There are several communication media used for AMR. These include, but are not limited to, spread-spectrum radio, telephone, power line carrier, and cellular telephone. The number of AMR customers under consideration by VECO, in the tens rather than hundreds, limits the economical choices for AMR communication to telephone and cellular telephone. In both of these systems, a third party provides the communication backbone. With small numbers of installations, it is cost prohibitive to install a dedicated communication infrastructure for AMR. Therefore it is our recommendation that telephone be the first communication choice for AMR.

A customer who is reluctant to provide access to a telephone line may relent if offered partial access to the load data. This data could be in the form of an average daily load profile. If the customer desires more sophisticated data, limited, read-only, access could be provided to the revenue meter. Most meters that incorporate AMR functions also have multiple levels of data access from read-only to full access.

If a telephone line is unavailable, a cellular modem can be used for wireless access of the data. The use of cellular telephone will reduce the data throughput speed. Therefore, if cellular telephone is to be used, the amount, and type, of data retrieved must be selected carefully.

Revenue Meter for AMR Installations

There are many three-phase revenue meters available that have AMR capabilities. The list of meters reduces considerably when you also require power quality monitoring. One revenue meter that is capable of modem communication and power quality monitoring is the EPM-9650Q from GE Industrial Systems (www.geindustrial.com). This meter is also available as the Nexus 1250 from Electro Industries (www.electroindustries.com). This is a panel-mount meter. A socket-based version is available as the 1270 from Electro Industries. The approximate cost of this meter is PHP160,000.

This meter meets all applicable IEEE standards for electricity metering and has been approved by Measurement Canada. The meter is compliant with the DNP3.0 communication protocol and is compatible with Itron's (www.itron.com) MV90 revenue data translation and billing system. Specifications for this meter presented in Appendix F.

Meter Interface Software

The software used to program this meter is called Communicator, both by GE and Electro Industries. The software is windows based and uses an easy menu-tree structure for setting metering parameters as shown in Figure 16-1.

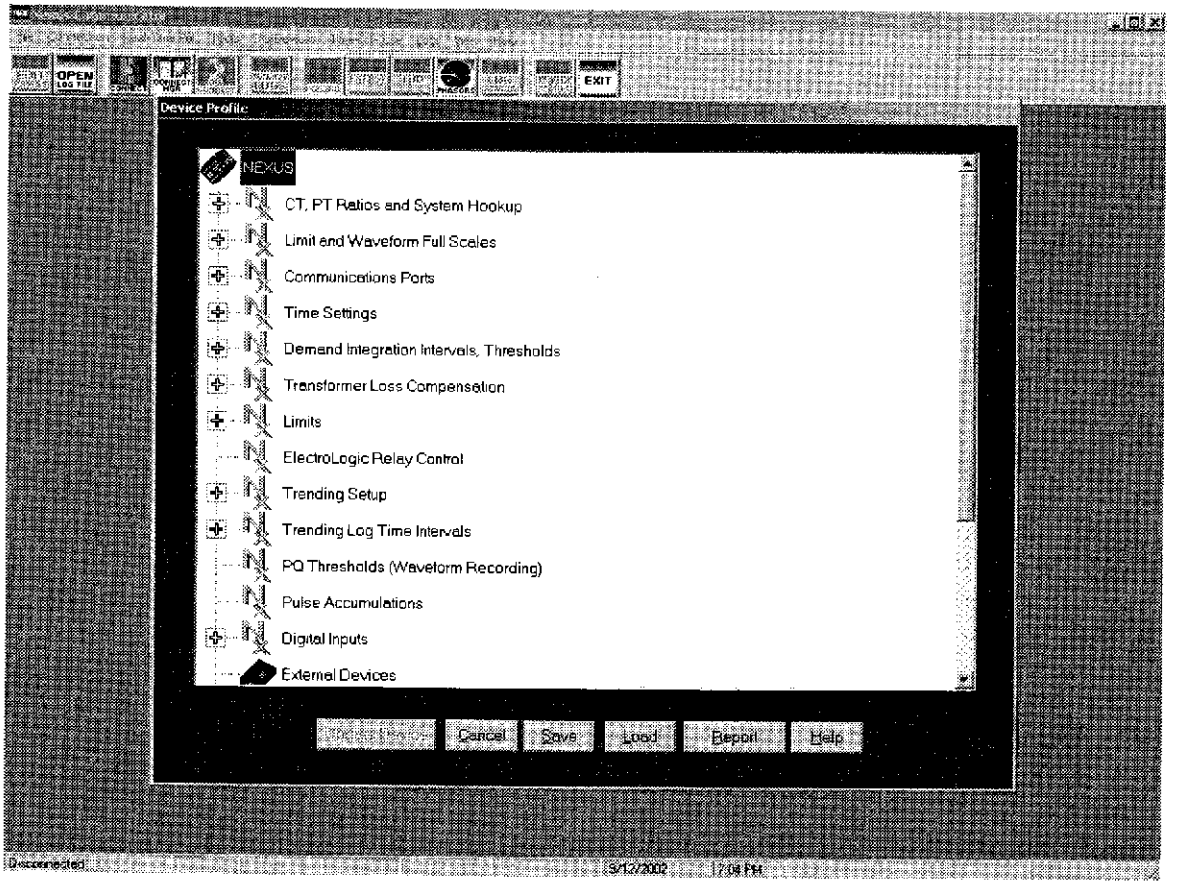


Figure 16-1
Communicator Software Screenshot

The Communicator software can also be used to download data from the revenue meter. Communication can be via direct connect (RS-232), Ethernet, or dialup modem. Power quality and load profile data can be downloaded for review and analysis without modifying the revenue data. This allows a group such as Engineering to access the data they need without putting the revenue data at risk.

Power Quality Capabilities

The power quality capabilities of this meter are quite impressive. The meter is capable of monitoring current level, voltage level, voltage unbalance, and harmonics. This is in addition to the types of data that are normally measured for revenue metering such as kWh, kW, kvar, kVA, etc. Figure 16-2 shows a plot of voltage events recorded on a Nexus 1250. Each point on the plot indicates a voltage anomaly. This particular meter has several voltage events on channel A caused by testing in EPRI PEAC's lab.

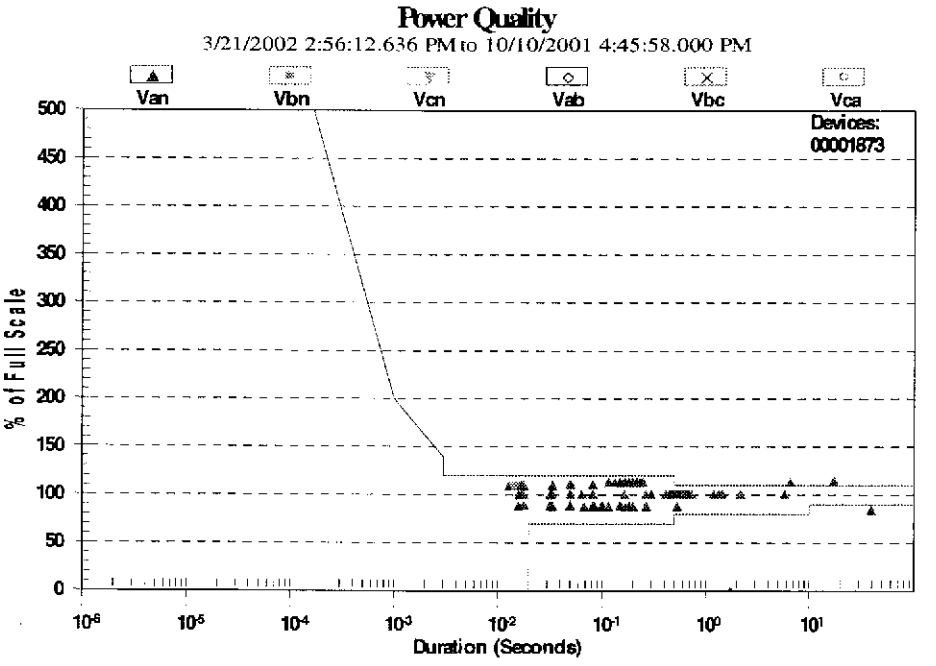


Figure 16-2
Power Quality Event Plot

The GE EPM-9650Q /Electro Industries Nexus 1250 is capable of logging any value which it can measure. This includes digital inputs that could be used to record the position of a transfer switch for example. The meter can also capture voltage and current waveforms during events. These waveforms are captured when a measured quantity exceeds a programmed limit. Figure 16-3 shows an example of a three-phase voltage waveform event captured when the phase A voltage exceeded a limit.

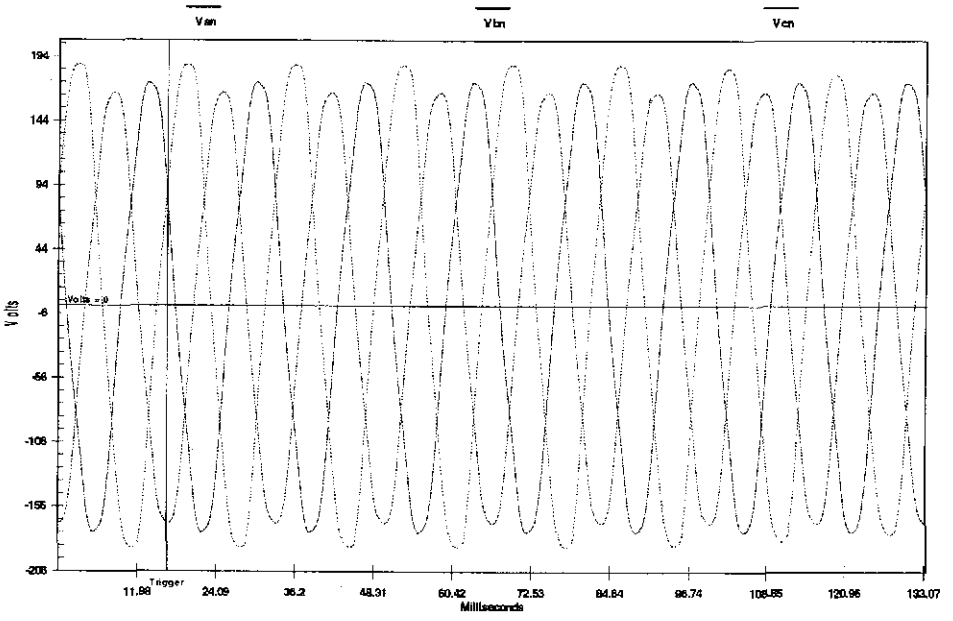


Figure 16-3
Waveform Data from the Nexus 1250

Conclusion

With the limited number of installations required by VECO, telephone is the best communication choice. The GE EPM-9650Q/Electro Industries Nexus 1250 is an ideal choice for installation at key customer locations when power quality data is as important as revenue data.

17
ROADMAP FOR DISTRIBUTION AUTOMATION

The roadmap for distribution automation should follow the priorities established in other sections of this reliability improvement study.

First, a robust communications backbone will have to be installed to support whatever distribution automation technology is selected. The fiber optic system recommended above satisfies this requirement.

The second step will be to install updated switching equipment. Again, recommendations as to this equipment are made in other sections of this reliability improvement study.

Then, the third step, equipment must be selected and installed at key switching locations that can be remotely controlled. Present equipment is not capable of remote control. The installation of this equipment must include the main ties between feeders.

As a fourth step, a software vendor needs to be selected. This should be considered in conjunction with the GE PowerOn, a prime candidate.

By following this roadmap, there will be a certain degree of overlap in the timing for the acquisition and deployment of the various elements of the distribution automation system. This will save both time and money. But only if the roadmap is included in a broader plan to implement the full range of recommendations in this reliability improvement study.

18
FINANCIAL ANALYSIS

This chapter was removed due to considerations of proprietary data.

19
SUMMARY OF RECOMMENDED EXPENDITURES

There are many methods that can be used to improve power quality and reliability in distribution systems. Many of these methods are discussed in this report. To facilitate the consideration of future investments, this chapter will list the estimated cost of the improvements recommended in this report, as well as provide some information on other possible expenditures that can be investigated further by Veco.

The remainder of this chapter was removed due to considerations of proprietary data.

20
FUTURE PROJECTS

This chapter was edited due to considerations of proprietary data.

Power Quality Monitoring System

EPRI has many years of experience in designing, specifying, and managing the installation of power quality monitoring systems for both utilities and industrial customers. EPRI's involvement can range from evaluation of hardware and software to the design and installation of turn-key monitoring systems. Pricing depends on the number of metered points and the level of EPRI involvement.

A
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B
COMMERCIAL AND INDUSTRIAL SAMPLE FORMS FOR OUTAGE-COST SURVEY

Some organizations have more than one building at a location, while others have buildings in several locations. For this survey, (_____) is interested in the building(s) that your organization occupies at and adjacent to this location:

If your organization shares a building with other organizations, answer the following questions only for the space your organization occupies at this location.

Survey responses will be strictly confidential.

Thank you for your participation!

In completing this survey, a power outage refers to a complete loss of electricity to your organization. Power outages can be caused by many factors, such as bad weather, traffic accidents, and equipment failures.

1. Has your organization experienced power outages in the last 12 months? *(CIRCLE ONE NUMBER)*

   1. No ---------- > SKIP TO QUESTION 3
   2. Yes

2. In general, how disruptive have these outages been to your organization? *(CIRCLE ONE NUMBER)*

   1 2 3 4 5 6 7

   Not at All Disruptive — Very Disruptive

3. Has your organization ever sent employees home during a power outage? *(CIRCLE ONE NUMBER)*

   1. No
   2. Yes

4. In general, how long can you wait for the power to be restored after a power outage before the costs to your organization become significant? *(FILL IN BLANKS)*

   _____Hours and _____Minutes

5. For what equipment does your organization need an electricity supply with fewer power outages? *(CIRCLE ALL THAT APPLY)*

   1. Computers
   2. Phones
   3. Security system
   4. HVAC systems (heating, ventilating, and air conditioning)
   5. Cash registers
   6. Data communication systems (such as local area networks)
   7. Other (please specify): _____

6. How much advance warning of a power outage does your organization need to significantly reduce the problems caused by a power outage? *(CIRCLE ONE NUMBER)*

   1. Advance notice would not reduce problem(s)
   2. At least 1 hour
   3. At least 4 hours
   4. At least 8 hours
   5. At least 24 hours

7. How satisfied are you with the number of outages your organization has experienced in the last 12 months? *(CIRCLE ONE NUMBER)*

1	2	3	4	5	6	7
Extremely Dissatisfied						Extremely Satisfied

8. How satisfied are you with the length of time it usually takes to restore service after an outage? *(CIRCLE ONE NUMBER)*

1	2	3	4	5	6	7
Extremely Dissatisfied						Extremely Satisfied

9. How satisfied are you with the responsiveness of the utility when you have a power outage? *(CIRCLE ONE NUMBER)*

1	2	3	4	5	6	7
Extremely Dissatisfied						Extremely Satisfied

The next section describes four different power outage scenarios. We would like to know the costs to your organization of adjusting to each of these power outages.

For many organizations, the costs incurred depend upon the particular situation, and may vary from day to day depending upon business conditions. So, for each outage scenario, you will be given the opportunity to report the range of outage costs that your organization might face (from low to high), as well as to estimate the cost that would be most likely to occur under average circumstances.

It is important to try to answer all of the questions. If a question is difficult for you to answer, please give us an estimate and feel free to write any comments about your answer in the margin. If the information is confidential, put a "C" in the blank provided.

Case 1: On a hot summer weekday, a complete power outage occurs at 3:00 p.m. without any warning. You do not know how long it will last, but after 1 hour your organization's electricity is fully restored. To summarize:

Case 1:COMPLETE POWER OUTAGE
Conditions: Hot summer weekday Start time: 3:00 p.m.
Warning: No advance notice Duration: 1 hour

10. How disruptive would this power outage be to your organization? *(CIRCLE ONE NUMBER)*

1	2	3	4	5	6	7
Not at All Disruptive						Very Disruptive

11. Would production or sales typically stop or slow down as a result of this power outage? *(CIRCLE ONE NUMBER AND FILL IN BLANK IF APPROPRIATE)*

1. No ----------> SKIP TO QUESTION 5

2. Yes ----------> _____Number of hours production or sales would stop or slow down (include time during and after the power outage)

12. What is the approximate dollar value of the production or sales that typically would be lost, at least temporarily, during the power outage and any slow period after the power outage? *(FILL IN BLANK)*

$_____ Value of lost production or sales

13. What percent of this production or sales typically would be made up? *(CIRCLE ONE NUMBER)*

|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|

0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%

14. Would there be labor costs associated with this power outage (such as salaries and wages to staff who would be unable to work or overtime pay to make up for lost production or sales)? *(CIRCLE ONE NUMBER AND INCLUDE COSTS IF APPROPRIATE)*

1. No

2. Yes—> $_____labor costs of staff unable to work during the power outage

$_____labor costs in overtime/extra shifts to make up lost production or sales

15. Would there be any damage costs associated with this power outage (such as damage to equipment or spoilage to a product)? *(CIRCLE ONE NUMBER AND INCLUDE COSTS IF APPROPRIATE)*

    1. No

    2. Yes —> $_____ damage to equipment
       $_____ damage to materials or products

16. Would there be additional tangible costs associated with this power outage (such as overhead and depreciation, extra restart costs, and costs to run and/or rent backup equipment)? *(CIRCLE ONE NUMBER AND INCLUDE COSTS IF APPROPRIATE)*

    1. No
    2. Yes —> $_____additional costs

17. If you had to put a dollar value on intangible costs due to this power outage (such as inconvenience or dissatisfied customers), what would these costs be? *(CIRCLE ONE NUMBER AND INCLUDE COSTS IF APPROPRIATE)*

    1. $0, there would not be any intangible costs
    2. $_____ intangible costs

18. In addition to the costs discussed above, some organizations may have savings associated with production that is never made up, such as unused materials or inventory, savings on your organization's fuel bill or from wages that are not paid. Would you experience any savings associated with this power outage? *(CIRCLE ONE NUMBER AND INCLUDE COSTS IF APPROPRIATE)*

    1. No
    2. Yes —> $_____ savings

19. Considering all of the costs you might experience as a result of this outage, please estimate the costs for the lowest cost case, the highest cost case, and the most likely case that you would experience. (Enter zero if none). *(FILL IN THE BLANKS)*

$_____	$_____	$_____
Lowest Total Outage Cost (Best Case)	Most Likely Total Outage Cost (Typical Case)	Highest Total Outage Cost (Worst Case)

Now we want to ask you about two outage scenarios (Cases 2 and 3), which are just slightly different from Case 1, and how your outage costs might differ.

Case 2: Suppose that the outage is identical to Case 1 *except that* makes radio and television announcements at 2:00 p.m. that a complete power outage will occur at 3:00 p.m. in your area and will last one hour. To summarize:

Case 2: COMPLETE POWER OUTAGE
Conditions: Hot summer weekday — Start time: 3:00 p.m.
Warning: One-hour advance notice — Duration: 1 hour

20. What is the likelihood that anyone in your organization would hear about this power outage in advance? *(CIRCLE ONE NUMBER)*

0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Extremely Unlikely					About 50/50					Extremely Likely

21. Assuming that someone did hear the advance warning, please estimate the costs for the lowest cost case, the highest cost case, and the most likely case that you would experience. (Enter zero if none). *(FILL IN THE BLANKS)*

$_____	$_____	$_____
Lowest Total Outage Cost (Best Case)	Most Likely Total Outage Cost (Typical Case)	Highest Total Outage Cost (Worst Case)

Case 3: Suppose that the outage is identical to Case 1 *except that* it lasts four hours instead of one hour. To summarize:

Case 3: COMPLETE POWER OUTAGE
Conditions: Hot summer weekday — Start time: 3:00 p.m.
Warning: No advance notice — Duration: 4 hours

22. Considering all of the costs you might experience as a result of this outage, please estimate the costs for the lowest cost case, the highest cost case, and the most likely case that you would experience. (Enter zero if none). *(FILL IN THE BLANKS)*

$_____	$_____	$_____
Lowest Total Outage Cost (Best Case)	Most Likely Total Outage Cost (Typical Case)	Highest Total Outage Cost (Worst Case)

Finally, we want to ask you about an outage that occurs during the winter season rather than the summer, to see how your outage costs might differ.

Case 4: Suppose that the outage occurs on a winter weekday at 4:00 p.m. without any warning. You do not know how long it will last, but after four hours your organization's electricity is fully restored. To summarize:

Case 4: COMPLETE POWER OUTAGE

Conditions:	Winter weekday	Start time:	4:00 p.m.
Warning:	No advance notice	Duration:	4 hours

23. Considering all of the costs you might experience as a result of this outage, please estimate the costs for the lowest cost case, the highest cost case, and the most likely case that you would experience. (Enter zero if none). *(FILL IN THE BLANKS)*

$_____	$_____	$_____
Lowest Total Outage Cost (Best Case)	Most Likely Total Outage Cost (Typical Case)	Highest Total Outage Cost (Worst Case)

Now we want to ask you about you about your interest in back-up service that could provide your organization with electricity in the event of a loss of power from the utility.

24. Assume that you know for certain that the power outage described in Case 1 (please refer to the box at the top of page, Case 1) will occur sometime during the next summer. If a supplier (other than_____) could provide your organization with electric back-up service, what is the highest one-time fee you think your organization would be willing to pay to avoid this particular power outage? *(FILL IN BLANK)*

$_____ (If you said $0, give reason why your organization would not be willing to pay anything to avoid the outage:

_____

_____

_____)

WHAT LEVEL OF RELIABILITY IS ACCEPTABLE

(_____) works to prevent power outages, but eliminating all outages could be very costly, if not impossible. The next set of questions helps us understand what you consider acceptable service from (_____)

25. If each of the following occurred, would you think you were getting acceptable or unacceptable service from (_____)? *(CIRCLE ONE NUMBER FOR EACH)*

		ACCEPTABLE	UNACCEPTABLE	DON'T KNOW
Outages lasting less than two seconds...				
a.	Once a day	1	2	3
b.	Once a week	1	2	3
c.	Once a month	1	2	3
d.	Once every 3 months	1	2	3
e.	Once every 6 months	1	2	3
f.	Once a year	1	2	3
Outages lasting a few minutes to an hour...				
a.	Once a day	1	2	3
b.	Once a week	1	2	3
c.	Once a month	1	2	3
d.	Once every 3 months	1	2	3
e.	Once every 6 months	1	2	3
f.	Once a year	1	2	3
Outages lasting 1 to 4 hours...				
a.	Once a day	1	2	3
b.	Once a week	1	2	3
c.	Once a month	1	2	3
d.	Once every 3 months	1	2	3
e.	Once every 6 months	1	2	3
f.	Once a year	1	2	3

ABOUT YOUR ORGANIZATION

Some background information about your organization will help us understand how power outages affect your type of organization. All of your answers are strictly confidential. The information will be used only to report comparisons among different types of organizations. We will never identify individuals or organizations with their responses. If the information is confidential, put a "C" in the blank provided.

26. Which of the following categories best describes your organization? *(CHECK ONE)*

a. Agriculture	_____	h. Lumber/mining/plastics	_____
b. Assembly/light industry	_____	i. Office	_____
c. Chemicals/paper/refining	_____	j. Oil/gas extraction	_____
d. Food processing	_____	k. Retail	_____
e. Grocery store/restaurant	_____	l. Stone/glass/clay/cement	_____
f. Habitation (health facility, college, prison, hotel)	_____	m. Transportation	_____
g. High tech	_____	n. Utility	_____

27. What is the approximate square footage of this facility (Note: "Facility" refers to the building(s) that your organization occupies at and adjacent to the location shown on the label attached to the front page of this survey)? *(FILL IN BLANK)*

_____Square feet

28. How many *full-time (30+* hours per week) employees are employed by your organization at this facility? *(FILL IN BLANK)*

_____Full-time employees

29. How many *part-time* or *seasonal* people are employed by your organization at this facility? *(FILL IN BLANKS)*

_____Part-time year-round employees	_____Part-time seasonal employees	_____Full-time seasonal employees

30. What is the approximate value of your organization's annual operations or services? *(FILL IN BLANK)*

    $_____ per year

31. What is the approximate value of your organization's total annual operating expenses (including labor, rent, materials, and other overhead expenses)? *(FILL IN BLANK)*

    $_____ per year

32. Approximately what percentage of your organization's annual operating budget is spent on energy costs (gas and electricity)? *(FILL IN BLANK)*

    $_____ %

33. Does your organization have any electrical equipment that is sensitive to fluctuations in voltage, frequency, short interruptions (less than two seconds), or other such irregularities in electricity supply? *(CIRCLE ONE NUMBER AND FILL IN BLANK IF APPROPRIATE)*

    1. No----------> SKIP TO QUESTION 10
    2. Yes What equipment? _____

34. Does your organization own or rent/lease any of the following power conditioning devices to protect this equipment? *(CHECK APPROPRIATE BLANK SPACES)*

    a. Back-up generator(s) _____
    b. Uninterruptible power supply _____
    c. Line conditioning device(s) _____
    d. Surge suppressor(s) _____
    e. Isolation transformer(s) _____

35. Does your organization have any electrical equipment that would continue to operate during a power outage? *(CIRCLE ONE NUMBER AND FILL IN BLANK IF APPROPRIATE)*

    1. No
    2. Yes what equipment?_____

If you have any additional comments, please feel free to write them below:

THANK YOU FOR YOUR HELP!

Please return this survey in the enclosed envelope to:

C
RESIDENTIAL SAMPLE FORM FOR OUTAGE-COST SURVEY

HOW DIFFERENT OUTAGE COSTS AFFECT YOUR HOUSEHOLD

(_____) wants to learn more about what power outage prevention is worth to you, and how much should be spent on it.

To do this, we need to know how different types of power outages affect your household. This survey asks about your reactions to two types of power outages—**momentary outages** and **prolonged outages**. Momentary outages occur when you lose power for 1 or 2 seconds while prolonged outages last for at least 5 minutes. If either type of outage occurs at your home you might have "out-of-pocket" costs from:

- Food spoilage
- Going out to eat
- Loss of self-employed home income, and
- Other items

These outages might also affect your household in many other ways.

By answering the questions on the following pages, you can help (_____) devise more cost effective service programs for the future. **There are no right or wrong answers. We simply want the best response you can provide.**

The next few questions concern your household's experience with prolonged power outages. Prolonged power outages occur when accidents, equipment failure, bad weather, or other problems result in the complete loss of electricity to your home for at least 5 minutes.

1. About how many prolonged power outages has your household experienced in the last 12 months? *(CIRCLE ONE NUMBER)*

   1. No Prolonged Outages
   2. 1-2 Prolonged Outages
   3. 3-5 Prolonged Outages
   4. 6-10 Prolonged Outages
   5. More than 10 Prolonged Outages
   6. Don't Know

2. Do you feel that the number of prolonged power outages at your home is: *(CIRCLE NUMBER)*

   1. Very Low
   2. Low
   3. Moderate
   4. High
   5. Very High

3. Do you have a back-up generator in your home? (*CIRCLE NUMBER*)

   1. NO
   2. YES (If YES, estimate cost of purchase) $_____

CASE #1
On a hot summer weekday, a prolonged power outage occurs at 3:00 p.m. without any warning. You do not know how long the power outage will last, but after one hour your household's electricity is fully restored.

4. What would your household usually do if this outage occurred? *(CIRCLE THE NUMBER OF ALL THAT APPLY)*

   1. Nothing, there is often no one home at this time
   2. Stay home and do other activities that don't require electricity
   3. Go out to eat, shop, go to work, or visit friends
   4. Other_____

5. Consider how many household members are usually at home at this time. Rate the following inconveniences your household might experience due to this one-hour outage from 1 being "not at all bothersome" to 5 being "very bothersome." *(CIRCLE ONE NUMBER FOR EACH IMPACT)*

	NOT AT ALL BOTHERSOME				VERY BOTHERSOME
Lost value of spoiled foods	1	2	3	4	5
Cost of going out to eat	1	2	3	4	5
Effects on leisure time	1	2	3	4	5
Annoyances and inconveniences of resetting clocks	1	2	3	4	5
Computer/appliance malfunction	1	2	3	4	5
Inconveniences in getting ready for work	1	2	3	4	5
Inconveniences in getting ready for school	1	2	3	4	5
Water pump/water source interruption	1	2	3	4	5
Other *(PLEASE SPECIFY)*_____	1	2	3	4	5

As you answer the following questions, keep in mind that during this 1-hour outage you do not know how long it will take to restore your electrical service.

6. Suppose (_____) could provide you with a credit on your bill each time your home experienced this outage, whether or not you were home. What would be the least amount that you would consider a fair payment for each time this outage occurred in your home? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

7. Suppose a **back-up service** was available to handle all of your household's electrical needs during this power outage. The supplier would bill you only for when and for how long the back-up service provided you with electricity.

If you were charged a fee for this service **only when you decided to use it** (by using an on/off switch in your home), what is the **most** you would be willing to pay for this service each time you used it to avoid this power outage? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

8. If you were charged a fee for the back-up service each time there was a power outage, **regardless of whether or not someone was at home**, what is the **most** you would be willing to pay for this service each time this service avoided this power outage? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

9. If you answered $0 to questions 6, 7, or 8, is that because the service is really worth nothing to you or is there some other reason?

_____ Worth nothing

____ Other reason *(EXPLAIN BELOW)*

CASE #2
On a very hot summer weekday (_____) announces a blackout. For this case, assume (_____) makes radio and television announcements at 2:00 p.m. that a complete power outage will occur at 3:00 p.m. in your area and last for 1 hour. This power outage is like Case 1 except (_____) gives advance warning that the power outage will occur.

10. What would your household usually do if this outage occurred? *(CIRCLE THE NUMBER OF ALL THAT APPLY)*

1. Nothing, there is often no one home at this time
2. Stay home and do other activities that don't require electricity
3. Go out to eat, shop, go to work, or visit friends
4. Other_____

11. Consider how many household members are **usually at home** at this time. Rate the following inconveniences your household might experience due to this one-hour outage from 1 being "not at all bothersome" to 5 being "very bothersome." *(CIRCLE ONE NUMBER FOR EACH IMPACT)*

	NOT AT ALL BOTHERSOME				VERY BOTHERSOME
Lost value of spoiled foods	1	2	3	4	5
Cost of going out to eat	1	2	3	4	5
Effects on leisure time	1	2	3	4	5
Annoyances and inconveniences of resetting clocks	1	2	3	4	5
Computer/appliance malfunction	1	2	3	4	5
Inconveniences in getting ready for work	1	2	3	4	5
Inconveniences in getting ready for school	1	2	3	4	5
Water pump/water source interruption	1	2	3	4	5
Other *(PLEASE SPECIFY)*_____	1	2	3	4	5

12. Suppose (_____) could provide you with a **credit on your bill** each time your home experienced this outage, **whether or not you were home**. What would be the **least amount** that you would consider a fair payment for each time this one-hour announced outage occurred in your home? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

13. Suppose a **back-up service** was available to handle all of your household's electrical needs during this power outage. The supplier would bill you only for when and for how long the back-up service provided you with electricity.

If you were charged a fee for this service **only when you decided to use it** (by using an on/off switch in your home), what is the **most** you would be willing to pay for this service each time you used it to avoid this one hour announced power outage? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

14. If you were charged a fee for the back-up service each time there was a power outage, **regardless of whether or not someone was at home**, what is the **most** you would be willing to pay for this service each time this service avoided this one hour announced power outage? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

15. If the outage described above occurred three days in a row during the summer, what is the most you would be willing to pay for back-up service to avoid this one hour announced power outage each time it occurred? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

CASE #3
On a hot summer weekday afternoon, a lightning storm in your area causes your electricity to go out for 1 or 2 seconds three different times between 4 p.m. and 6 p.m. At the time, however, you do not know how long the storm will last or how many times the outages will occur.

16. Consider how many household members are **usually at home** at this time. Rate the following inconveniences your household might experience due to the lights and other appliances losing power from 1 being "not at all bothersome" to 5 being "very bothersome." *(CIRCLE ONE NUMBER FOR EACH IMPACT)*

	NOT AT ALL BOTHERSOME				VERY BOTHERSOME
Lost value of spoiled foods	1	2	3	4	5
Cost of going out to eat	1	2	3	4	5
Effects on leisure time	1	2	3	4	5
Annoyances and inconveniences of resetting clocks	1	2	3	4	5
Computer/appliance malfunction	1	2	3	4	5
Inconveniences in getting ready for work	1	2	3	4	5
Inconveniences in getting ready for school	1	2	3	4	5
Water pump/water source interruption	1	2	3	4	5
Other *(PLEASE SPECIFY)*_____	1	2	3	4	5

17. Suppose (_____) could provide you with a **credit on your bill** each time your home experienced this situation, **whether or not you were home** during the storm. What

would be the **least amount** that you would consider a fair payment for each day this outage occurred in your home? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

As you answer the following questions, keep in mind that you do not know how long the storm will last or how many outages will occur.

Suppose **power-conditioning** equipment that produced a constant electrical power supply could be installed on your household's electrical circuits to eliminate the outages. You would be billed only for when the equipment eliminated the outages.

18. If you were charged a fee for this service **only when you decided to use it** (by using an on/off switch in your home) what is the **most** you would be willing to pay each day the equipment operated? *(CIRCLE OR CIRCLE NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

19. If you were charged a fee for the power conditioning equipment each day the equipment operated, **regardless of whether or not someone was at home**, what is the **most** you would be willing to pay for this service each time this service avoided this power outage? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

20. If the 1 or 2 outages occurred several times a week in the afternoon throughout the summer, what would be the **most** you would be willing to pay each day for a power conditioning service that eliminated all the outages? *(CIRCLE OR ENTER NUMBER)*

$0	$0.10	$0.25	$0.50	$1	$2	$3
$4	$5	$6	$8	$10	$12	$15
$20	$25	$30	$40	$50	OTHER: $_____	

21. If you answered $0 to questions 18, 19, or 20 is that because the service would really be worth nothing to you or is there some other reason?

_____ Worth nothing

_____ Other reason *(EXPLAIN BELOW)*

WHAT RELIABILITY IS ACCEPTABLE

(_____) works to prevent power outages, but eliminating all outages could be very costly, if not impossible. The next questions help us understand what you consider acceptable service from (_____).

22. If each of the following occurred, would you think you were getting acceptable or unacceptable service from (_____)? *(CIRCLE ONE NUMBER FOR EACH)*

	DON'T KNOW	UNACCEPTABLE	ACCEPTABLE
Outages lasting less than a minute...			
1. Once a day	1	2	3
2. Once a week	1	2	3
3. Once a month	1	2	3
4. Once every 3 months	1	2	3
5. Once every 6 months	1	2	3
6. Once a year	1	2	3
Outages lasting a few minutes to an hour...			
7. Once a day	1	2	3
8. Once a week	1	2	3
9. Once a month	1	2	3
10. Once every 3 months	1	2	3
11. Onceevery6 months	1	2	3
12. Once a year	1	2	3
Outages lasting 1 to 4 hours...			
13. Once a day	1	2	3
14. Once a week	1	2	3
15. Once a month	1	2	3
16. Once every 3 months	1	2	3
17. Once every 6 months	1	2	3
18. Once a year	1	2	3

ABOUT YOU AND YOUR HOUSEHOLD

Answers to these questions will help us understand how power outages affect different kinds of households.

23. Which of the following best describes your residence? *(CIRCLE ONE NUMBER)*

1. Single Family Detached Home

2. Single Family Attached Home (Town House, Villa, Duplex)
3. Apartment/Condo
4. Mobile Home

24. Do you own or rent this residence? *(CIRCLE ONE NUMBER)*

1. Own/Buying
2. Rent/Lease
3. OTHER *(PLEASE SPECIFY)* _____

25. How long have you lived at this address? *(CIRCLE ONE NUMBER)*

1. Less than 1 year
2. Between 1 year and less than 2 years
3. Between 2 and less than 5 years
4. Between 5 and less than 10 years
5. Longer than 10 years

26. Does anyone in your household use your residence as a place of business? *(CIRCLE NUMBER)*

1. YES 2. NO

27. Is anyone in your household using electrical medical equipment such as a respirator or heart monitoring equipment? *(CIRCLE NUMBER)*

1. YES 2. NO

28. Is anyone in your household confined to a sickbed? *(CIRCLE NUMBER)*

1. YES 2. NO

D
SAMPLE DESIGN FOR OUTAGE COST SURVEY

Overview of Sample Design Process

In a world of unrestricted resources, a utility interested in measuring the outage costs of it customers would simply survey each customer. This is called a census. However, the cost of surveying all utility customers is astronomical, and the utility must instead settle for surveying a subset of its customers. These results can be used to infer what the outage costs are for the wider population[20]. The subset of customers included in the study is called the survey sample, and the way in which it is chosen strongly influences both the validity and precision of the outage cost estimates made for the population at large.

This section describes in detail how to design and select a customer sample for an outage cost study to ensure that valid, unbiased, and relatively precise inferences can be made about the population of outage costs. It begins with a discussion of the objectives of sample design, and then describes two types of sample designs: simple random and stratified random—these explain the relationships between sample size and statistical precision. Finally, the procedures required to design and select an outage cost survey sample are described in detail.

Objectives of Sample Design

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

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

[20] In recent years, the U.S. Department of Commerce has realized that the costs of carrying out a census of the U. S. population significantly outweigh the benefits obtained from focusing on all citizens and for the 2000 census intends to use a survey-based approach.

The smaller the percentage deviation (of the sample mean from the true population mean), the more precise the sample mean is as an estimator for the population mean.

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

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

Simple Random Sampling

As described above, the objective in sampling is to achieve the greatest statistical precision possible in the outage cost estimates for a given sample size (determined by the project budget).[21] In the case of simple random sampling, the formula for statistical precision is given by:

$$r = \left(\frac{\sigma}{\mu}\right) \bullet Z \bullet \left(\frac{1}{\sqrt{n}}\right) \qquad \textbf{Eq. D-1}$$

Where:

r is precision,

σ is the standard deviation of the variable of interest,

μ is the mean of the variable of interest,

Z is the standard normal variate (that is, Z equals 1.96 for a 95 percent confidence interval), and

n is the sample size.

Because precision is measured as a percentage deviation of the sample mean from the true population mean, lower values of r denote greater precision, and are more desirable than higher values. For example, an r value of 0.10 means that the true population mean is within

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

±10 percent of the sample mean value, while a value of 0.05 means that the true mean is within a narrower range of ±5 percent of the sample mean. Thus the researcher's objective is to develop a design that minimizes r.

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

Suppose that a researcher at General Utility wants to design a simple random sample for an outage cost survey of its residential customer class. Table D-1 shows the information available to the research to help design the sample. From General Utility's billing records, the researcher knows the number of customers in the residential class. However, because General Utility has never before performed a residential outage cost survey, information is not available on the mean or standard deviation of customer outage cost, the variable of interest. Information is available, though, on average monthly energy usage, which is known to be positively correlated with outage cost. The researcher thus decides to use average energy usage as a proxy for outage cost to estimate the precision levels attainable from samples of varying sizes.[22]

Table D-1
Available Information on General Utility's Residential Population

Number of Customers	Mean (kWh per month)	Standard Deviation (kWh)	Coefficient of Variation
1,275,000	508	357	0.70

Table D-1 shows that the distribution of average monthly electric usage over General Utility's 1.275 million residential customers have a mean of 508 kWh per month and a standard deviation of 357 kWh. The ratio of the standard deviation to the mean, or the coefficient of variation, is 0.70. With this information, the researcher can calculate the level of statistical precision achievable from any particular combination of confidence level and sample size.

Suppose that the researcher specifies a 95 percent confidence level and has a budget sufficient to fund an outage cost survey administered to 500 customers. Equation D-1 can then be used to calculate the level of precision in the outage cost estimates that is obtainable from a simple random sample. Table D-2 presents the details of this calculation. A sample size of 500 will yield

[22] After the survey has been completed and information on outage costs collected, the researcher can use these estimates to refine the precision estimates.

an estimate of average customer outage cost that is within ±6.2 percent of the true population average with 95 percent confidence.[23]

Table D-2
Precision Calculation Under Simple Random Sampling

Number of Customers	Mean (kWh per month)	Standard Deviation (kWh)	Coefficient of Variation	Z	n	r
1,275,000	508	357	0.70	1.96	500	0.062

A precision level of ±12.3 percent may or may not be acceptable to the General Utility researcher, depending upon the importance of the uses to which the outage cost data will be put and the associated costs of decisions based upon imprecise estimates. Suppose that the researcher desires a more accurate estimate that is within ±4 percent of the true population mean outage cost. As noted earlier, the way to achieve this is to increase the size of the sample.[24] Equation D-1 can be used to calculate the statistical precision associates with a number of different sizes. Table D-3 shows the results.

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

Number of Customers	Mean (kWh per month)	Standard Deviation (kWh)	Coefficient of Variation	Z	n	r
1,275,000	508	357	0.70	1.96	500	0.062
1,275,000	508	357	0.70	1.96	1000	0.044
1,275,000	508	357	0.70	1.96	1500	0.036
1,275,000	508	357	0.70	1.96	2000	0.031

Because the sample size enters as a square root function in the denominator of Equation D-1, precision improves at a declining rate as sample size is increased. Table D-3 shows that a quadrupling of the sample size from 500 to 2000 is required to double the level of precision (that is, halve the value of r). Figure D-1 shows a graphical representation of the relationship between sample size and precision. It is clear from the graph that there are diminishing returns to the improvements in precision that can be obtained by increasing the sample size. Because such increases come at a cost to the utility, there is some point at which the utility researcher decides that the value of the improved precision no longer is worth the additional survey cost.

[23] This means that if the process of selecting a random sample, surveying customers, and estimating average outage cost was repeated a large number of times, that the average outage cost estimate would be within 12.3 percent of the true value 95 percent of the time.
[24] This increase in sample size will, of course, increase the cost of administering the survey and requires a larger budget.

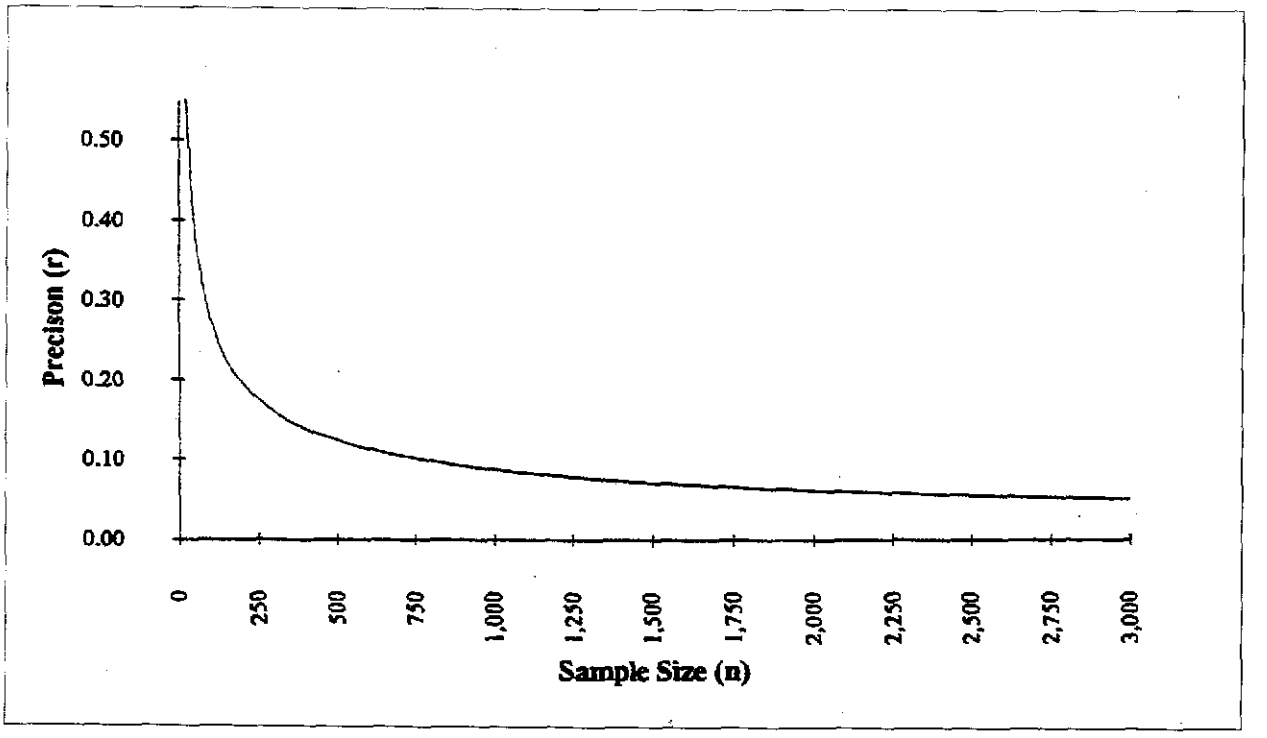

Figure D-1
Relationship Between Sample Size and Statistical Precision Under Simple Random Sampling

Returning to our example, a sample size of 1000 would be not large enough to yield the desired precision level of ±4 percent, whereas a sample size of 1500 would yield more than the required amount. A sample size somewhere in between these two figures would yield the desired precision level. By rewriting Equation D-1 to express n in terms of r, then plugging in a value of 0.04 for r, we can solve for the minimum required sample size. A sample size of 1183 will yield the desired precision level of ±4 percent.

Stratified Random Sampling

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

Stratified designs are obtained by segmenting the customer population into a number of groups, known as sampling cells or strata, according to some stratifying variable or set of variables. Gains in precision are achieved by choosing stratification schemes that divide the population into groups with similar outage costs. Intuitively, the improved precision results from the fact that within-group variations in the variable of interest are much smaller than its overall variation in the population. As a consequence, sample points can be allocated in a more optimal way among the sampling cells to increase precision without changing the overall sample size. Continuing with our example, suppose that General Utility's residential population is stratified into five

usage groups as shown in Table D-4 below. The mean and standard deviation of monthly electricity usage for the overall population are still 508 and 357 kWh, respectively, but these statistics vary substantially across the five usage groups. The important thing to note is that each cell in the stratified design has a smaller coefficient of variation than the overall population (because the cells have been constructed in such a way that groups similar customers together). This is the feature of stratified designs that lead to gains in precision.

Table D-4
Available Information on General Utility's Residential Population by Sampling Cell

Usage Category	Number of Customers	Mean	Standard Devation	Coefficient of Variation
Very small	379,000	205	73	0.36
Small	375,000	401	57	0.14
Medium	333,000	615	90	0.15
Large	150,000	996	155	0.16
Total	1,275,000	508	357	0.70

In the case of stratified random sampling, the formula for precision is a bit more complicated than Equation D-1. Assuming that there are H different sampling cells denoted by the subscript *h*, precision is calculated as:

$$\rho = \left(\frac{1}{\mu}\right) \bullet z \bullet \sum_{h=1}^{H} \frac{W_h^2 \bullet s_h^2}{n_h} \qquad \textbf{Eq. D-2}$$

Where:

W is the sampling weight of cell *h* (that is, the proportion of the population residing in cell *h*),

s_h is the standard deviation of the variable of interest within cell *h*, and

n_h is the sample size in cell *h*.

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

Stratified Proportional Designs

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

$$h = n * W_h, \quad h = 1.....H \qquad \textbf{Eq. D-3}$$

Where:

W is the sampling weight of cell *h* (that is, the proportion of the population residing in cell *h*).

Returning to our example, recall that using a simple random sample design, the General Utility researcher would have to survey 1183 customers to obtain the desired level of accuracy of ±4 percent. However, suppose that the budget available to conduct the survey would not support a survey of any more than 500 customers. Could a stratified proportional design improve precision sufficiently to meet the researcher's objective? Table D-5 provides the answer.

Table D-5
Stratified Proportional Sample Design

Usage Category	Number of Customers	Mean	Standard Deviation	Coefficient of Variation	Z	n	r
Very small	379,000	205	73	0.36	1.96	149	0.057
Small	375,000	401	57	0.14	1.96	147	0.023
Medium	333,000	615	90	0.15	1.96	131	0.025
Large	150,000	996	155	0.16	1.96	59	0.040
Very Large	38,000	1,711	551	0.32	1.96	15	0.164
Total	1,275,000	508				500	0.022

Under this design, the 500 sample points are distributed among the five sampling cells in proportion to the number of customers in the residential population residing in each cell. Because the "very small" category is the most populous with 30 percent of the customers (379,000 out of the 1.275 million in total), this cell receives 30 percent of the sample points (149 out of 500). In contrast, the "very large" category is allocated just 3 percent of the sample points, consistent with its population share. The last column shows the statistical precision resulting from this allocation. The precision varies from cell to cell, but the overall precision is improved from ±6.2 percent to ±2.2 percent by moving from a simple random to a stratified proportional design.

This is more than sufficient to meet the researcher's 4 percent precision target. A comparison with Table D-2 shows that attaining an equivalent level of precision from a simple random design should require a sample size in excess of 2000 customers.[25]

One primary advantage of a proportional design is that it is easy to implement and will usually result in improved precision over a simple random sample. In addition, proportional designs make analysis of the resulting outage cost survey data a relatively simple task, without requiring complicated weighting schemes to extrapolate the sample information to the entire population.[26] However, proportional designs will not generally yield the most precise outage cost estimates attainable from a given overall sample size. To maximize precision, the researcher needs to use a more sophisticated design known as a Neyman allocation.

Stratified Neyman Designs

The Neyman allocation is derived by mathematically solving the optimization problem of allocating the total number of sample points among the H cells in a way that minimizes r (that is, maximizes precision) in Equation D-2. The solution to this optimization problem is given by the following formula:

$$h = n \bullet \left(\frac{W_h \bullet \sigma_h}{\sum_h W_h \bullet \sigma_h} \right) h = 1, \ldots\ldots H \qquad \textbf{Eq. D-4}$$

As Equation D-4 shows, the Neyman design allocates the total number of sample points in proportion to each sampling cell's population-weighted standard deviation. It is instructive to contrast the Neyman design with its proportional counterpart given by Equation D-3. With a proportional design, the allocation is entirely dependent upon the population customer share, W_h. This share is an important factor in a Neyman design, too, but it is not the only determinant. A Neyman design also accounts for the variation in the variable of interest within each sampling cell (as measured by the cell's standard deviation). By doing so, the Neyman design ensures the greatest level of precision possible from any given sample size.

Table D-6 shows the stratified Neyman design for our example. A comparison with the proportional design given by Table D-5 shows that the Neyman design allocates relatively more sample points to the higher usage categories, because of their larger standard deviations. This is especially apparent in the highest usage category, where the Neyman design allocates 85 sample points compared to 15 with a proportional design. The last row in Table D-6 shows that the overall level of precision with a Neyman design improves to ±1.7 percent compared to the ±2.2 percent figure yielded by a proportional design.

[25] The actual sample size required with a simple random design to achieve a precision level of ±2.2 percent would be approximately 3750 customers.

[26] [Note other possible advantages to proportional designs, citing Seeto and Keane PUF article.]

Table D-6
Stratified Neyman Sample Design

Usage Category	Number of Customers	Mean	Standard Deviation	Coefficient of Variation	Z	n	r
Very small	379,000	205	73	0.36	1.96	112	0.066
Small	375,000	401	57	0.14	1.96	87	0.030
Medium	333,000	615	90	0.15	1.96	122	0.026
Large	150,000	996	155	0.16	1.96	94	0.031
Very Large	38,000	1711	551	0.32	1.96	85	0.068
Total	1,275,000	508				500	0.017

This example illustrates the gains in precision that can be achieved by employing stratified sampling designs. In practice, the magnitude of the improvement in precision depends upon the variability of underlying data and the degree to which the variable of interest is related to the stratification variable. In the case of customer outage costs, previous research has shown that outage costs vary widely across customers, especially in the commercial and industrial sectors. Furthermore, empirical studies have shown that outage costs are at least somewhat related to electric usage. Consequently, reasonable gains in precision are generally achievable by stratifying the sample by customer usage.[27]

Sample Selection Procedures

This section describes the procedures to be employed to design and select a customer outage cost survey.

Define Sampling Frame

[27] Further gains may be possible by employing additional stratification variable which are related to customer outage costs. For example, in the commercial and industrial sectors, the researcher may wish to use a business type variable to further stratify customers. Any variable, which is being considered for use in stratifying the population, though, must meet two conditions. First, the variable should be closely related to customer outage cost. Otherwise, the gains in precision, which result, will be small or negligible. Second, the utility must know its value for every customer in its population, because it needs to exhaustively classify all customers before selecting the sample. This second condition eliminates a variable like residential household income, which may be correlated with outage cost but is not known to the utility.

The first step in developing a sample design is to define the sampling frame, or the population from which the survey sample will be chosen. The sampling frame usually corresponds fairly closely to a particular customer class definition. However, the researcher may want to exclude certain accounts from the sampling frame because their inclusion would provide information of relatively low value to the utility.[28] Alternatively, the researcher may wish to add in a customer group not ordinarily included in the standard customer class definition of the sampling frame should be guided by the ultimate uses to which the outage cost estimates will be put.

For example, a utility researcher planning a commercial outage cost survey has a choice of sampling frame definitions. Many utilities refer to non-residential customers with small- to medium-sized kilowatt demands as "commercial" customers. Using this size-based definition, a small manufacturing business would be classified as a commercial customer, and included in the sampling frame. Alternatively, though, the researcher could use a definition base upon the customer's economic activity (as determined by the SIC code variable in the utility's billing files). In this case, the small manufacturer would be classified as an industrial customer, and excluded from the sampling frame. Which definition should the researcher use? It depends upon the ultimate use of the outage cost estimates. Suppose that the primary objective of the study is to collect outage cost estimates to plan generation reliability. In this case, the researcher knows that the per-event outage cost information collected from the survey will have to be divided by estimates of customer unserved energy derived from load research data. If the unserved energy estimates correspond to a size-based definition of the commercial class (that is, they are derived from load research samples selected from a population of customers defined by their kilowatt demands), then for consistency the outage cost survey sampling frame should likewise be based upon customer size, and not economic activity.

Develop Sample Design

Once the sampling frame has been defined, the next step is to design the sample. The design process in turn has four component tasks. First, the researcher needs to identify a stratification variable or set of variables. As discussed above, customer usage should be chosen as one stratification variable. Depending upon the availability of other information, the researcher may also wish to choose an additional stratification variable or two.

Once the candidate stratification variables have been selected, the researcher needs to define the boundaries between the cells. For example, if usage is chosen, the researcher needs to determine how many usage categories there will be and what the break-points will be between the categories. Similarly, if business type is used as a stratification variable, then the researcher must decide on the number of distinct business types to employ and develop a mapping scheme to uniquely and exhaustively assign customers to a business type category. In the case of

[28] For example, the researcher might wish to exclude billboards from a study of small commercial/industrial outage costs. Because these accounts are known not to be using electricity during system peak hours when generation-related outages would occur, the researcher would not want to "waste" limited survey points on them.

continuous variables like usage, the researcher can employ the Dalenius-Hodges procedure to aid in developing the sampling cell boundaries.[29]

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

Select Sample

Once the final sample design has been determined, the final step is to actually select the sample. This is a relatively simple process. After all customers in the sampling frame have been assigned to their appropriate sampling cells, the researcher draws independent simple random samples of the desired sizes from each cell. Operationally, this is done using a computer program that, for each sampling cell, assigns random numbers to each customer, sorts the customers by the value of this random number, then selects the first n_h customers.

[29] For a discussion of this technique see "Minimum Variance Stratification", Dalenius T. and Hodges J.L. Jr., 1959, *Journal Of The American Statistical Association*, vol. 54, pp. 88-101.

E
ECONOMIC EVALUATION USING METHODOLOGY OUTLINED IN IEEE 1346

Introduction

Annex A of IEEE 1346 explains a method to evaluate and analyze the financial impact of compatibility. It is intended to be generic in coverage and does not necessarily represent any particular type of business. Although generic guidance is provided, the user should very carefully ensure that all applicable costs particular to the user's specific operation are identified if the analysis is to provide meaningful results. The method presented is intended to identify general costs associated with power quality disruptions and is not intended to function as an accounting system. In other words, for compatibility evaluation, it is only necessary to identify approximate losses. Determining accurate losses would be more appropriate after the magnitude of the problem is known and resources are available to investigate deeper.

A method to analyze the overall cost of compatibility is also presented based on simple pay back. Individual businesses may have different methods or criteria than those presented here. However, it is intended to provide a technique that can quickly identify cost saving potentials associated with compatibility.

Cost of Disruption

There are several suggestions to help ensure a successful cost of disruption evaluation. First, involve everyone who is impacted by the disruption in estimating the loss. The most obvious are those familiar with the operational impact of equipment disruption such as front-line workers, supervisors, and maintenance technicians. The list should also include finance and accounting personnel who may have established methods of estimating financial losses associated with downtime. Sales and marketing personnel can represent the impact on customers and management can provide the longer-term, strategic consequences of disruptions. The evaluation requires a balance of both high level and detailed perspectives. Data from the business' information tracking system should be used wherever possible.

Second, if for some aspects of the analysis it is not possible to obtain documented costs, use the best estimate of someone experienced with the process. Their estimates are often later shown to be surprisingly accurate.

Finally, where the personnel involved are not sufficiently knowledgeable or objective to offer good estimates, observational sampling may be applied. Keep in mind this guideline is only intended to expose approximate costs.

The costs discussed here are listed in the cost of disruption evaluation form shown in Figure E-1. A separate tabulation should be generated for each compatibility evaluation.

COST OF DISRUPTION FORM

Downtime related

- Increased buffer inventories (value of incremental inventories * WACC) ____
- *Lost work*
  - *Idled labor*
    - Disrupted process (man-hrs * unloaded labor rate) ____
    - Starved process (man-hrs * unloaded labor rate) ____
  - *Lost production*
    - Lost profits (unbuilt product * profit margin) ____
    - *Makeup production*
      - Overtime labor + premium ____
      - Overtime operating cost ____
      - Expedited shipping premiums ____
      - Late delivery fees ____
  - *Cost to repair damaged equipment*
    - Repair labor ____
    - Repair supplies ____
    - Repair parts ____
    - *Cost of replacement part availability*
      - Expedited shipping of parts ____
      - *or*
      - Carrying cost of parts ____
  - *Cost of recovery*
    - Secondary equipment failures (treat as repairs) ____
    - Recovery labor inefficiency ____

Product quality

- Replacement value of scrap (BOM value + labor value) ____
- Blemished product lost profit margin ____
- *Rework cost*
  - Labor ____
  - Manufacturing supplies ____
  - Replacement parts ____

Miscellaneous

- *Customers dissatisfaction*
  - Lost business ____
  - Avoided customers due to longer lead time ____
- Fines and Penalties ____
- Other ____

TOTAL ____

Figure E-1
Sample Cost of Disruption Evaluation Form

Downtime Related

Lost Work

The product or service is not generated for a period of time until recovery is complete. A process flow of the product or service should be developed for the other supplied processes (either inside or outside the facility) or customers to determine when and how they are impacted.

On manufacturing lines, there may be inventory buffers between processes (work in progress, or WIP) to prevent minor disruptions from cascading to downstream processes. These WIP inventories may be increased to reduce the impact of future disruptions as a preventive measure. The capital tied up in WIP can be found by estimating the average number of units in these buffers and multiplying by the value of the components of a partially assembled unit, usually with the aid of operation's bill of materials (BOM). This capital, multiplied by the finance group's cost of capital (weighted average cost of capital, or WACC), yields the cost to the business of carrying excess inventory.

However, where insufficient WIP buffers exist in a manufacturing line, or in service industries where WIP cannot be carried, processes downstream of a disrupted operation will eventually be disrupted themselves. Stoppage of downstream work is referred to as starving processes. The cost is the cost of paying idle employees at the starved processes. Supervision should be able to estimate the average idle man-hours of labor (those employees who cannot be deployed to other operations, conduct preventive maintenance, perform housekeeping, or other similar activities) and accounting should be able to provide the unloaded (that is, no benefits) labor rate.

If lost work can be recovered with overtime, the additional costs associated with overtime should be added. This includes the labor costs, overtime premiums, and the additional costs to operate the facility and equipment outside normal schedules. The operations and accounting groups should be able to help estimate these costs. Furthermore, there may be additional transportation costs for expedited deliveries. Trucks may be delayed for departure and the user charged for the delay (demurrage). Expedited shipping may also be needed to compensate for the production delay. Some customer contracts may have late delivery penalties. The sales group would have information on the history of and conditions for these penalties.

However, for a work disruption taking place at a facility at maximum capacity where the lost work cannot be made up at the impacted location or another location, the resulting downtime should be shown as lost profits to the business for the number of units which could not be created and delivered.

Repair

Unlike lost work, the repair of equipment damaged often generates a paper trail available from either maintenance or operations. The exact components repaired depend on the circumstances.

There are several types of costs involved. First, there is the cost of hardware replaced, either parts or complete machinery. In addition to the cost of buying the replacement hardware, there

are costs associated with holding repair parts in inventory (treat similarly to WIP carrying costs, above) and with any special transportation costs for expedited shipping of components. Second, there is repair labor. The business may have repair personnel on staff and their labor may not represent an additional cost unless they must work overtime. Alternatively, an outside firm may be called to perform the repairs. In such a case all the repair labor costs should be included. Finally, there may be delayed repairs. The equipment is temporarily repaired to bring the line back up, but additional, later work is necessary to complete the job.

Recovery

Recovery-related costs are those costs associated with returning to normal operation, including labor- and production-related inefficiencies. Labor costs should also be included in the consideration.

Both industrial and commercial equipment recovering from a crash can exhibit secondary failures. This may be because of the additional stresses of an uncontrolled shutdown or latent failures that are exposed by the cycling. They should be included in the analysis.

There is also a psychological effect on the work force of their process unraveling, especially of a complex process. This is particularly true if the incident is overwhelming and appears beyond the employee's control to prevent. Employees may not feel disposed to restore rhythm if the disruption is near the end of the shift. Full recovery may only be possible with the next shift or next day. Line supervisors are the best source of employee productivity changes after a disruptive event.

Product Quality

The losses attributable to product quality are scrap and rework.

Scrap is product that is damaged beyond economic repair by the disruption. The loss is the value of the product at the point of damage in the process. (It may be helpful to conduct this calculation by determining replacement cost—that is, the cost of replacing damaged product by good product at a similar stage of processing.) Operations should have scrap information, both quantities and costs. These costs may be partially offset if damaged product may be sold as seconds at lower price. Sales should be aware of such opportunities.

Rework is repairing damaged product to the point it is acceptable, including both labor and materials. Again, the operations group should be tracking rework data. In information technology applications, rework is usually the most significant cost. Data must be recreated, inputted, and or verified. In research and development work, often entire experiments may need to be repeated.

Miscellaneous

There are other costs that are less quantifiable than those discussed above. This section outlines some of these with possible metrics. Where the investigation yields what appear to be truly uncertain estimates, it is better to leave these numbers out of the main cost/benefit argument and present them as separate, supporting figures.

Customers may be dissatisfied with late delivery or delayed service, resulting in potential loss of reputation and, with it, customer contracts. The sales department may have anecdotal evidence of sales, and profits, lost because of failed deliveries. By working with operations to develop a probability for missed deliveries based on disruptions, one can estimate the number of times deliveries may be missed annually to a customer. Using this figure, with past anecdotes and examples as guides, sales may be able to project a lost sales figure.

Sales may be quoting excessively long delivery lead times to cover potential downtime problems and ensure that the company can always meet delivery schedule. These longer lead times may be driving away potential customers. If power disruptions are a significant cause of long downtimes (which maintenance or operations should know), the reduction or elimination of disruptions should allow a shorter delivery lead time. Given an estimate of how many hours or days the lead time could be shortened, sales may be able to estimate new business.

Disruptions may jeopardize employee or customer safety, such as in the chemical or health care industries. Process disruption may lead directly to an environmental release that can result in a government fine and bad publicity. There may be costs associated with possible litigation associated with other aspects of the event. Safety hazards or actual injuries may result in safety agency fines or additional medical/insurance costs.

Determine the best-case and worst-case scenarios with associated probabilities of such events, before approaching the relevant departments for assistance.

Financial Analysis of Alternatives

With an estimate of the annual number of compatibility-related process disruptions and an estimate of the cost of disruption, alternatives may be evaluated. The alternatives include, but are not limited to buying less sensitive equipment, contracting for service guarantees from the electric utility, or adding mitigating devices. Some of the alternatives add new equipment or increase the cost of planned equipment. These are initial or capital costs. Other costs are outlays incurred throughout the life of the project. These are operating costs. The incremental cost of a method to improve compatibility is compared against the resulting savings. If the savings exceed the costs over a specified period of time (such as two years), the project can be considered viable.

It is assumed that the business has a well-defined project approval process, with appropriately rigorous analyses based on the present values of the resulting net cash flows. The following is meant to supplement, not supplant, a more traditional cash flow approach.

Before developing the rigorous analyses needed for capital and expense requests, it is often helpful to have developed a quick "back-of-the-envelope" estimate of costs versus benefits. The quick estimate should be comprehensive in breath but not necessarily in depth. All potential costs and benefits should be examined, but the projected numbers need not be accurate to the last detail. This estimate gives an indication of the magnitude of the net benefit. Indeed, if estimated benefits are significantly greater than projected costs, more detailed, traditional analyses may not be necessary for project approval.

Table E-1 outlines the major components of such an analysis. Investment consists of any one-time cost required to implement the changeover project. This could include the incremental cost of less-sensitive process equipment determined by requesting two proposals from the equipment supplier for normal and less-sensitive versions. There may be additional hardware costs that allow quicker recovery from a disruption. Additional equipment to mitigate incompatibilities may be added such as uninterruptible power supplies installed at process electronics or "custom power" equipment to supply conditioned power for part or all of a facility. The costs to install the equipment and remove old equipment should also be added.

Table E-1
Compatibility Financial Analysis

Investment	*Examples*	**Return**	*Examples*
One-time capital outlay	*Enhanced equip, Custom Power*	Annual benefit	*Cost of reduced downtime*
+		-	
Installation	*Installation cost*	Ongoing annual expense	*UPS maintenance, Premium utility service*
Net Investment		Net annual return	

The annual benefit is the reduced down time costs as a result of the project based on the reduction of disruptions and the cost per disruption. The annual number of disruptions prevented is multiplied by the cost per disruption to determine the annual benefit. The net annual return is found by netting out the outgoing annual expenses as a result of the project. This can include the maintenance and electrical energy costs associated with operating mitigating equipment or the additional cost of an electric utility premium service contract.

The payback period is the number of months of benefits required for the project to break even. In this case, the payback period is the net investment divided by the net annual return (see Equation E-1).

$$Payback\,(months) = (net\,investment\,/\,net\,annual\,return) * 12 \qquad \textbf{Eq. E-1}$$

If more accuracy is desired, the net present value can be calculated of the one-time investment set against a stream of net annual returns yielding the total value of the project. However, the simple payback calculation should be sufficient for the purposes of estimation. Generally, a

payback period of less than 24 months signals a project that should be critically examined with more rigorous analysis.

F
PRODUCT SPECIFICATIONS

This appendix contains specifications for much of the equipment discussed in this report. The intent is to provide information that the utilities can use when purchasing equipment. Each heading gives the specific manufacturer and model of the equipment. This is followed by a generic specification that can be used in purchasing.

Recloser Specifications

35 kV Series Trip, Vacuum Interruption and Oil Insulation (Cooper VWV38x)

EQUIPMENT SPECIFICATIONS: Automatic Circuit Recloser with series trip, vacuum interruption and oil insulation.

STANDARDS

The recloser covered by this specification shall be manufactured and tested in accordance with ANSI C37.60.

RATINGS

Maximum Design Voltage, kV	38.0
Nominal Operating Voltage, kV	34.5
Basic Insulation Level (BIL), kV	150
60 Hertz Withstand Voltage, kV	
Dry, One Minute	70
Wet, Ten Seconds	60
Continuous Current Rating, Amps	560
Interrupting Rating, Symmetric Amps	12000

DUTY CYCLE

PERCENT OF INTERRUPTING RATING	NUMBER OF UNIT OPERATIONS	MAXIMUM CIRCUIT X/R VALUE
15-20	88	4
45-55	112	8
90-100	32	15
	Total: 232	

FEATURES

The recloser shall be mechanically and electrically trip free.

All three poles of the recloser shall be operated simultaneously by a solenoid-controlled spring operating mechanism.

The solenoid shall provide energy for closing the main contacts and for storing energy in the opening spring for a tripping operation.

The closing solenoid coil shall be connected internally phase-to-phase on the source side of the recloser through a suitable contactor.

Bushings shall be of wet process porcelain, terminals shall be of the universal clamp type and shall accommodate number 1/0 through 500 MCM conductor.

Bushing creepage distance shall be 26 1/2".

Current interruption shall occur in sealed vacuum interrupters, one interrupter per pole.

A three-stage auxiliary switch shall be provided.

The recloser interrupting time shall be 0.045 seconds maximum.

The recloser shall be shipped filled with oil to the proper level. A dipstick shall be provided for checking oil level, a low oil level sight gauge shall be provided.

The recloser shall be shipped mounted on a substation type frame, complete with a tank lifting windlass.

The mounting frame shall have a grounding pad which will accommodate two No. 2/0 to 250 MCM conductors.

Manually closing and opening shall be accomplished by means of a manual operating handle located under a sleet hood external to the recloser. This handle located under a sleet hood external to the recloser. This handle shall also provide indication of recloser lockout.

A contact position indicator shall be provided, located under the recloser sleet hood.

One operation to lockout (non-reclosing) shall be accomplished by means of an external handle located under the sleet hood.

An operations counter shall be provided to count recloser operations, located under the sleet hood.

Overcurrent detection shall be provided by a set of three series trip coils, one per phase.

Time delay on tripping shall be provided by a set of three time delay units, one per phase.

The number of fast phase trip operations shall be selectable by means of a Sequence Selector internally located in the recloser. Selections shall be 0 - 1 - 2 - 3 - 4 number of fast trip operations.

The number of operations to lockout shall be selectable from 2 to 4 operations by means of an operations selector internally located in the recloser.

25 kV Hydraulic Electronic Vacuum Recloser (Cooper KFVE)

EQUIPMENT SPECIFICATIONS:

Automatic Circuit Recloser with electronic control, vacuum interruption, and oil insulation.

STANDARDS

The recloser covered by this specification shall be manufactured and tested in accordance with ANSI, IEEE and NEMA Standards.

QUALITY

The manufacturing facility shall be independently certified to meet ISO 9001 Standards.

RATINGS

Ratings as a minimum shall be as follows:

Maximum Design Voltage, kV	27.0
Nominal Operating Voltage, kV	2.4-24.9
Impulse withstand, 1.2 x 50 microsecond surge (BIL), Crest kV	125
Low frequency withstand voltage	
Dry, One Minute, kV	60
Wet, Ten Seconds	50

Radio influence voltage measured at 1000 kHz, 16.4 kV, shall not exceed 100 microvolts.

Frequency, Hz	50/60
Continuous current, amperes	400
Interrupting current, symmetrical amps	6,000
Cable charging current, amps	5
Magnetizing interrupting current, amps	14

DUTY CYCLE

PERCENT OF INTERRUPTING RATING	NUMBER OF UNIT OPERATIONS	MAXIMUM CIRCUIT X/R VALUE
15-20	96	4
45-55	120	8
90-100	32	15
total:	248	

MECHANICAL LIFE

Minimum of 2500 operations

OVERLOAD CAPABILITY (after level-off at rated continuous current)

Maximum Hours At:

Continuous Current Rating, Amps	125% of Continuous Current Rating	150% of Continuous Current Rating
400	4	2

CREEPAGE (in.)

26 1/2 "

RECLOSER FEATURES

The overcurrent sensing, recloser sequencing and tripping shall be electronically controlled.

The recloser shall be mechanically and electrically trip free.

All three poles of the recloser shall be operated simultaneously by a solenoid-controlled spring operating mechanism.

The solenoid shall provide energy for closing the main contacts and for storing energy in the opening spring for a tripping operation.

Current interruption shall occur in vacuum interrupters, providing long contact life.

Each vacuum interrupter shall be serialized.

Available closing voltages shall be phase to phase operating voltage (± 15%), 48 VDC, 125 VDC, 250 VDC, 120 VAC, 240 VAC.

The recloser interrupting time shall be 0.025 seconds maximum.

The recloser shall be of single tank construction with ground connector to accommodate No. 8 SOL through 2/0 STR conductor.

External stainless steel hardware shall be provided as standard.

An O-ring shall be used in a groove in the head casting to provide controlled compression.

The recloser shall be shipped with oil filled to the proper level. A vented dipstick shall be provided for checking oil level.

The bushings shall be of wet process porcelain. Bushing terminals shall be universal clamp type to accommodate 1/0 through 500 MCM conductors.

Bushing creepage distance shall be 26 1/2".

Sensing bushing current transformers, 1000:1 ratio, for use with a control, shall be mounted internally in the recloser on bushings 1,3,5.

A lever shall be provided for manually tripping the recloser.

15 kV Hydraulic Electronic Vacuum Recloser

EQUIPMENT SPECIFICATIONS:

Automatic Circuit Recloser with electronic control, vacuum interruption, and oil insulation.

STANDARDS

The recloser covered by this specification shall be manufactured and tested in accordance with ANSI, IEEE and NEMA Standards.

QUALITY

The manufacturing facility shall be independently certified to meet ISO 9001 Standards.

RATINGS

Ratings as a minimum shall be as follows:

Maximum Design Voltage, kV	15.5
Nominal Operating Voltage, kV	2.4-14.4
Impulse withstand, 1.2 x 50 microsecond surge (BIL), Crest kV	110
Low frequency withstand voltage	
Dry, One Minute, kV	50
Wet, Ten Seconds	45

Radio influence voltage measured at 1000 kHz, 9.4 kV, shall not exceed 100 microvolts.

Frequency, Hz	50/60
Continuous current, amperes	400
Interrupting current, symmetrical amps	6,000
Cable charging current, amps	5
Magnetizing interrupting current, amps	14

DUTY CYCLE

PERCENT OF INTERRUPTING RATING	NUMBER OF UNIT OPERATIONS	MAXIMUM CIRCUIT X/R VALUE
15-20	96	3
45-55	120	7
90-100	32	14
total:	248	

MECHANICAL LIFE

Minimum of 2500 operations

OVERLOAD CAPABILITY (after level-off at rated continuous current)

Maximum Hours At:

Continuous Current Rating, Amps	125% of Continuous Current Rating	150% of Continuous Current Rating
400	4	2

CREEPAGE (in.)

11 5/8 "

RECLOSER FEATURES

The overcurrent sensing, recloser sequencing and tripping shall be electronically controlled.

The recloser shall be mechanically and electrically trip free.

All three poles of the recloser shall be operated simultaneously by a solenoid-controlled spring operating mechanism.

The solenoid shall provide energy for closing the main contacts and for storing energy in the opening spring for a tripping operation.

Current interruption shall occur in vacuum interrupters, providing long contact life.

Each vacuum interrupter shall be serialized.

Available closing voltages shall be phase to phase operating voltage (± 15%), 48 VDC, 125 VDC, 250 VDC, 120 VAC, 240 VAC.

The recloser interrupting time shall be 0.025 seconds maximum.

The recloser shall be of single tank construction with ground connector to accommodate No. 8 SOL through 2/0 STR conductor.

External stainless steel hardware shall be provided as standard.

An O-ring shall be used in a groove in the head casting to provide controlled compression.

The recloser shall be shipped with oil filled to the proper level. A vented dipstick shall be provided for checking oil level.

The bushings shall be of wet process porcelain. Bushing terminals shall be universal clamp type to accommodate 1/0 through 500 MCM conductors.

Bushing creepage distance shall be 26 1/2".

Sensing bushing current transformers, 1000:1 ratio, for use with a control, shall be mounted internally in the recloser on bushings 1,3,5.

A lever shall be provided for manually tripping the recloser.

Regulator Specifications

7.2 kV Single-Phase Step Voltage Regulator (Cooper: for use on a 12.47 kV multi-grounded wye system)

1. GENERAL

1.1 This specification covers electrical, mechanical, and safety features and characteristics of outdoor, single-phase, oil-immersed, step-type voltage regulators. The voltage regulators must be completely self- contained and provide 10% regulation in thirty-two (32) steps of approximately 5/8% each. Forced air (FA) ratings are not acceptable.

1.2 The regulators furnished under this specification shall be designed, manufactured, and tested in accordance with ANSI Standard C57.15, latest revision thereof. That standard shall be a part of this specification.

1.3 Regulator rating and operating voltage shall be as specified on the inquiry (7.2 kV single-phase for use on a 12.47kV multi-grounded wye distribution system).

1.4 A price adder shall be provided for furnishing a regulator rated and nameplated 55°C/65°C rise.

1.5 The regulator shall be furnished with ANSI Type II mineral oil per ASTM D-3487. The oil shall contain less than 1 part per million PCBs at time of manufacture, and this shall be so stated on the regulator nameplates.

2.0 CONSTRUCTION

2.1 The regulators shall be designed such that they can be partially or completely untanked for inspection and maintenance without disconnecting any internal electrical or mechanical connections. A military specification-style quick disconnect shall be provided with a solid state automatic current transformer shorting device.

2.2 The tap-changing mechanism shall be motor-driven, quick-break type, and shall be completely oil-immersed.

2.3 The regulator shall be of a sealed-tank construction to permit operation at 65°C rise without increasing the oxidation rate of the oil. A pressure-relief device shall be supplied which vents at approximately 4 psig.

2.4 The external parts of the tank and control enclosure shall be painted ANSI #70 gray. The inside of the tank and bottom of the cover shall also be primed and/or painted.

2.5 The regulator coil shall include thermally-upgraded insulation to permit operation of the regulator up to 65°C rise without loss of life to the insulating system. At 65°C rise, the regulator shall provide 12% extra current capacity over the base current rating. A suitably patterned, epoxy-coated insulation paper shall be used in the winding. Prior to assembly of the core and coil assembly, the winding shall be baked with sufficient mechanical pressure exerted on the winding to assure a complete bonding of the insulation to improve its short-circuit current withstand capabilities.

3. STANDARD EXTERNAL FEATURES

3.1 The BIL rating of the bushings shall be compatible with the BIL of the regulator, and all bushings 15 kV and above shall have a minimum creep distance of 18 inches. The bushing designations (S, L, and SL) shall be permanently marked on the regulator cover adjacent to the bushings. The S, L, and SL bushings must be interchangeable with each other.

3.2 For regulators rated 1200 A and below, each bushing shall include a threaded 1.125" - 12 UNF-2A stud. For regulators rated above 1200 A, each bushing shall include a 1.5" - 12UNF -2A stud. Connectors integral to the bushing are not acceptable. The following connectors shall be included:

[ ] None

[ ] Clamp-type terminals: 150 Amp and below, #6 to 250 MCM
150 Amp to 668 Amp, #6 to 800 MCM

[ ] NEMA H Spade Connectors

3.3 All regulators shall be provided with an external metal oxide varistor (MOV) bypass arrester connected across the series winding.

3.4 An external oil sight gauge shall be provided which indicates oil level at 25°C ambient temperature.

3.5 An external position indicator shall indicate the tap changer position. The position indicator shall be mounted above the oil level and shall be slanted downward at a 45-degree angle for ease of reading from below when the regulator is pole mounted.

3.6 Regulators rated 668 amps and below shall include the ADD-AMP feature which will permit additional current carrying capabilities at reduced regulation as shown below, but not to exceed 668 amps. The ADD-AMP adjustment shall be located inside the position indicator faceplate to prevent inadvertent adjustment.

Regulation (percent)	Current (Percent of 55°C rating)
+/- 10.0	100
+/- 8.75	110
+/- 7.5	120
+/- 6.25	135
+/- 5.0	160

3.7 Mounting bosses shall be provided for the addition of lightning arresters adjacent to the source (S), load (L), and source-load (SL) bushings. The bosses shall be fully welded around their circumference. Spot welding is not acceptable.

3.8 All regulators shall have a 1" drain valve with sampling device and a 1" upper filter press connection.

3.9 A handhole with cover shall be provided on top of the regulator for inspection purposes and for access to terminals used for reconnection of regulators for lower-voltage operation.

3.10 Regulators rated 250 kVA and below shall be pole-mounted and provided with welded-on hanger brackets. Regulators rated 167 kVA and above shall be provided with a base suitable for securing them to a pad or elevating structure. All regulators must be capable of being secured to elevating structures.

3.11 Regulators with pole-mounting hanger brackets shall be provided with two 1/2" - 13 UNC welded ground bosses located diagonally opposite from each other. Regulators with substation base mounts shall be provided with two ground pads located diagonally opposite from each other. Each pad shall have two 1/2" - 13 UNC ground provisions. All grounding provisions are to be located near or on the base of the regulator.

3.12 Each regulator shall be provided with two laser-etched nameplates, one mounted on the control enclosure and the other mounted on the regulator tank. The nameplates shall have the manufacturer code and serial number barcoded with "3 of 9" coding with a 0.25" minimum height.

4. REGULATOR CONTROL

4.1 The regulator control panel shall be mounted in a weather-resistant enclosure which is capable of being padlocked. The control enclosure shall have an external 1/2" - 13 UNC welded ground boss.

4.2 The control panel shall be hinge-mounted and designed for easy inspection and replacement. The front panel assembly shall be constructed to provide direct control interchangeability without requiring removal of the control enclosure. Visible means shall be provided to de-energize the control and short the current transformer prior to control testing or removal.

4.3 All leads in the control shall be either color coded or labeled for easy identification.

4.4 All printed circuit boards shall be conformal coated for fungi and moisture protection.

4.5 A ratio correction transformer shall be provided inside the control enclosure for easy access to fine voltage adjustment. Ratio correction taps and the corresponding system voltage shall be clearly identified on the regulator nameplates.

4.6 The regulator control panel shall include the following items:

a. A three-position voltage source switch, labeled INTERNAL-OFF-EXTERNAL, which allows the regulator to be operated from an internal potential source, operated from an external source, or de- energized.

b. A three-position AUTOMATIC-OFF-MANUAL control switch which allows automatic or manual operation of the regulator, or allows the control to be turned off. Supervisory motor control shall be permitted only when the switch is in the AUTOMATIC position.

c. A spring-loaded three-position manual RAISE-LOWER toggle switch, which shall only be active when the AUTOMATIC-OFF-MANUAL switch is in the manual position.

d. A position indicator drag hand reset switch, located on the front panel.

e. A neutral indicating light, which is actuated via the tap changer to provide neutral indication.

f. A six-digit operations counter, which counts every tap change.

g. Separate motor and panel fuses, which are replaceable from the front panel. Fuse size shall be clearly marked below each fuse. One set of spare fuses shall be included in the control enclosure.

h. A means to indicate whether the voltage is inside or outside the set voltage band.

i. Voltage test terminals, which connect to the load side (L bushing) of the regulator.

j. External voltage source terminals, which allow control and tap changer operation from an external 120 vac source. A means shall be provided to prevent energizing the high-voltage bushings from the external source.

k. Control knob locking devices which prevent inadvertent adjustment of settings. The locking device shall be operable with a flat head screwdriver.

4.7 The control shall have provisions for setting the following parameters:

a. Set voltage shall be adjustable from 105 to 135 volts in increments no larger than I volt.

b. Set voltage bandwidth shall be adjustable from I to 6 volts in increments no larger than 0.5 volts.

c. Time delay shall be adjustable from 10 to 120 seconds in increments of 10 seconds.

d. Line drop compensator settings consisting of resistance and reactance which shall be individually adjustable from 0 to 24 volts. A means shall be provided to set the polarity of these settings.

4.8 The control shall have provisions to allow remote override of regulator operation via discrete (analog) supervisory control. Terminals shall be provided on the back panel as follows:

For motor raise:	Two terminals for normally-open, momentary-close contacts.
For motor lower:	Two terminals for normally-open, momentary-close contacts.
For auto inhibit:	Two terminals for normally-closed, latch-open contacts.

5. TESTING

All regulators shall be tested in accordance with the latest ANSI standards. In addition, every voltage regulator shall receive an impulse test at 100% rated BIL on the source (S) and source-load (SL) bushings to assure full integrity of the insulation system.

14.4 kV Single-Phase Step Voltage Regulator (Cooper: for use on a 25 kV multi-grounded wye system)

1. GENERAL

1.1 This specification covers electrical, mechanical, and safety features and characteristics of outdoor, single-phase, oil-immersed, step-type voltage regulators. The voltage regulators must be completely self- contained and provide 10% regulation in thirty-two (32) steps of approximately 5/8% each. Forced air (FA) ratings are not acceptable.

1.2 The regulators furnished under this specification shall be designed, manufactured, and tested in accordance with ANSI Standard C57.15, latest revision thereof. That standard shall be a part of this specification.

1.3 Regulator rating and operating voltage shall be as specified on the inquiry (14.4 kV single-phase for use on a 25 kV multi-grounded wye distribution system).

1.4 A price adder shall be provided for furnishing a regulator rated and nameplated 55°C/65°C rise.

1.5 The regulator shall be furnished with ANSI Type II mineral oil per ASTM D-3487. The oil shall contain less than 1 part per million PCBs at time of manufacture, and this shall be so stated on the regulator nameplates.

2.0 CONSTRUCTION

2.1 The regulators shall be designed such that they can be partially or completely untanked for inspection and maintenance without disconnecting any internal electrical or mechanical connections. A military specification-style quick disconnect shall be provided with a solid state automatic current transformer shorting device.

2.2 The tap-changing mechanism shall be motor-driven, quick-break type, and shall be completely oil-immersed.

2.3 The regulator shall be of a sealed-tank construction to permit operation at 65°C rise without increasing the oxidation rate of the oil. A pressure-relief device shall be supplied which vents at approximately 4 psig.

2.4 The external parts of the tank and control enclosure shall be painted ANSI #70 gray. The inside of the tank and bottom of the cover shall also be primed and/or painted.

2.5 The regulator coil shall include thermally-upgraded insulation to permit operation of the regulator up to 65°C rise without loss of life to the insulating system. At 65°C rise, the regulator shall provide 12% extra current capacity over the base current rating. A suitably patterned, epoxy-coated insulation paper shall be used in the winding. Prior to assembly of the core and coil assembly, the winding shall be baked with sufficient mechanical pressure exerted on the winding to assure a complete bonding of the insulation to improve its short-circuit current withstand capabilities.

3. STANDARD EXTERNAL FEATURES

3.1 The BIL rating of the bushings shall be compatible with the BIL of the regulator, and all bushings 15 kV and above shall have a minimum creep distance of 18 inches. The bushing designations (S, L, and SL) shall be permanently marked on the regulator cover adjacent to the bushings. The S, L, and SL bushings must be interchangeable with each other.

3.2 For regulators rated 1200 A and below, each bushing shall include a threaded 1.125" - 12 UNF-2A stud. For regulators rated above 1200 A, each bushing shall include a 1.5" - 12UNF -2A stud. Connectors integral to the bushing are not acceptable. The following connectors shall be included:

[ ] None
[ ] Clamp-type terminals: 150 Amp and below, #6 to 250 MCM
150 Amp to 668 Amp, #6 to 800 MCM
[ ] NEMA H Spade Connectors

3.3 All regulators shall be provided with an external metal oxide varistor (MOV) bypass arrester connected across the series winding.

3.4 An external oil sight gauge shall be provided which indicates oil level at 25°C ambient temperature.

3.5 An external position indicator shall indicate the tap changer position. The position indicator shall be mounted above the oil level and shall be slanted downward at a 45-degree angle for ease of reading from below when the regulator is pole mounted.

3.6 Regulators rated 668 amps and below shall include the ADD-AMP feature which will permit additional current carrying capabilities at reduced regulation as shown below, but not to exceed 668 amps. The ADD-AMP adjustment shall be located inside the position indicator faceplate to prevent inadvertent adjustment.

Regulation (percent)	Current (Percent of 55°C rating)
+/- 10.0	100
+/- 8.75	110
+/- 7.5	120
+/- 6.25	135
+/- 5.0	160

3.7 Mounting bosses shall be provided for the addition of lightning arresters adjacent to the source (S), load (L), and source-load (SL) bushings. The bosses shall be fully welded around their circumference. Spot welding is not acceptable.

3.8 All regulators shall have a 1" drain valve with sampling device and a 1" upper filter press connection.

3.9 A handhole with cover shall be provided on top of the regulator for inspection purposes and for access to terminals used for reconnection of regulators for lower-voltage operation.

3.10 Regulators rated 250 kVA and below shall be pole-mounted and provided with welded-on hanger brackets. Regulators rated 167 kVA and above shall be provided with a base suitable for securing them to a pad or elevating structure. All regulators must be capable of being secured to elevating structures.

3.11 Regulators with pole-mounting hanger brackets shall be provided with two 1/2" - 13 UNC welded ground bosses located diagonally opposite from each other. Regulators with substation base mounts shall be provided with two ground pads located diagonally opposite from each other. Each pad shall have two 1/2" - 13 UNC ground provisions. All grounding provisions are to be located near or on the base of the regulator.

3.12 Each regulator shall be provided with two laser-etched nameplates, one mounted on the control enclosure and the other mounted on the regulator tank. The nameplates shall have the manufacturer code and serial number barcoded with "3 of 9" coding with a 0.25" minimum height.

4. REGULATOR CONTROL

4.1 The regulator control panel shall be mounted in a weather-resistant enclosure which is capable of being padlocked. The control enclosure shall have an external 1/2" - 13 UNC welded ground boss.

4.2 The control panel shall be hinge-mounted and designed for easy inspection and replacement. The front panel assembly shall be constructed to provide direct control interchangeability without requiring removal of the control enclosure. Visible means shall be provided to de-energize the control and short the current transformer prior to control testing or removal.

4.3 All leads in the control shall be either color coded or labeled for easy identification.

4.4 All printed circuit boards shall be conformal coated for fungi and moisture protection.

4.5 A ratio correction transformer shall be provided inside the control enclosure for easy access to fine voltage adjustment. Ratio correction taps and the corresponding system voltage shall be clearly identified on the regulator nameplates.

4.6 The regulator control panel shall include the following items:

a. A three-position voltage source switch, labeled INTERNAL-OFF-EXTERNAL, which allows the regulator to be operated from an internal potential source, operated from an external source, or de- energized.

b. A three-position AUTOMATIC-OFF-MANUAL control switch which allows automatic or manual operation of the regulator, or allows the control to be turned off. Supervisory motor control shall be permitted only when the switch is in the AUTOMATIC position.

c. A spring-loaded three-position manual RAISE-LOWER toggle switch, which shall only be active when the AUTOMATIC-OFF-MANUAL switch is in the manual position.

d. A position indicator drag hand reset switch, located on the front panel.

e. A neutral indicating light, which is actuated via the tap changer to provide neutral indication.

f. A six-digit operations counter, which counts every tap change.

g. Separate motor and panel fuses, which are replaceable from the front panel. Fuse size shall be clearly marked below each fuse. One set of spare fuses shall be included in the control enclosure.

h. A means to indicate whether the voltage is inside or outside the set voltage band.

i. Voltage test terminals, which connect to the load side (L bushing) of the regulator.

j. External voltage source terminals, which allow control and tap changer operation from an external 120 vac source. A means shall be provided to prevent energizing the high-voltage bushings from the external source.

k. Control knob locking devices which prevent inadvertent adjustment of settings. The locking device shall be operable with a flat head screwdriver.

4.7 The control shall have provisions for setting the following parameters:

a. Set voltage shall be adjustable from 105 to 135 volts in increments no larger than 1 volt.

b. Set voltage bandwidth shall be adjustable from 1 to 6 volts in increments no larger than 0.5 volts.

c. Time delay shall be adjustable from 10 to 120 seconds in increments of 10 seconds.

d. Line drop compensator settings consisting of resistance and reactance which shall be individually adjustable from 0 to 24 volts. A means shall be provided to set the polarity of these settings.

4.8 The control shall have provisions to allow remote override of regulator operation via discrete (analog) supervisory control. Terminals shall be provided on the back panel as follows:

For motor raise:	Two terminals for normally-open, momentary-close contacts.
For motor lower:	Two terminals for normally-open, momentary-close contacts.
For auto inhibit:	Two terminals for normally-closed, latch-open contacts.

5. TESTING

All regulators shall be tested in accordance with the latest ANSI standards. In addition, every voltage regulator shall receive an impulse test at 100% rated BIL on the source (S) and source-load (SL) bushings to assure full integrity of the insulation system.

19.9 kV Single-Phase Step Voltage Regulator (Cooper: for use on a 34.5 kV multi-grounded wye system)

1. GENERAL

1.1 This specification covers electrical, mechanical, and safety features and characteristics of outdoor, single-phase, oil-immersed, step-type voltage regulators. The voltage regulators must be completely self- contained and provide 10% regulation in thirty-two (32) steps of approximately 5/8% each. Forced air (FA) ratings are not acceptable.

1.2 The regulators furnished under this specification shall be designed, manufactured, and tested in accordance with ANSI Standard C57.15, latest revision thereof. That standard shall be a part of this specification.

1.3 Regulator rating and operating voltage shall be as specified on the inquiry (19.9 kV single-phase for use on a 34.5 kV multi-grounded wye distribution system).

1.4 A price adder shall be provided for furnishing a regulator rated and nameplated 55°C/65°C rise.

1.5 The regulator shall be furnished with ANSI Type II mineral oil per ASTM D-3487. The oil shall contain less than 1 part per million PCBs at time of manufacture, and this shall be so stated on the regulator nameplates.

2.0 CONSTRUCTION

2.1 The regulators shall be designed such that they can be partially or completely untanked for inspection and maintenance without disconnecting any internal electrical or mechanical connections. A military specification-style quick disconnect shall be provided with a solid state automatic current transformer shorting device.

2.2 The tap-changing mechanism shall be motor-driven, quick-break type, and shall be completely oil-immersed.

2.3 The regulator shall be of a sealed-tank construction to permit operation at 65°C rise without increasing the oxidation rate of the oil. A pressure-relief device shall be supplied which vents at approximately 4 psig.

2.4 The external parts of the tank and control enclosure shall be painted ANSI #70 gray. The inside of the tank and bottom of the cover shall also be primed and/or painted.

2.5 The regulator coil shall include thermally-upgraded insulation to permit operation of the regulator up to 65°C rise without loss of life to the insulating system. At 65°C rise, the regulator shall provide 12% extra current capacity over the base current rating. A suitably patterned, epoxy-coated insulation paper shall be used in the winding. Prior to assembly of the core and coil assembly, the winding shall be baked with sufficient mechanical pressure exerted on the winding to assure a complete bonding of the insulation to improve its short-circuit current withstand capabilities.

3. STANDARD EXTERNAL FEATURES

3.1 The BIL rating of the bushings shall be compatible with the BIL of the regulator, and all bushings 15 kV and above shall have a minimum creep distance of 18 inches. The bushing designations (S, L, and SL) shall be permanently marked on the regulator cover adjacent to the bushings. The S, L, and SL bushings must be interchangeable with each other.

3.2 For regulators rated 1200 A and below, each bushing shall include a threaded 1.125" - 12 UNF-2A stud. For regulators rated above 1200 A, each bushing shall include a 1.5" - 12UNF -2A stud. Connectors integral to the bushing are not acceptable. The following connectors shall be included:

[ ] None

[ ] Clamp-type terminals: 150 Amp and below, #6 to 250 MCM
150 Amp to 668 Amp, #6 to 800 MCM

[ ] NEMA H Spade Connectors

3.3 All regulators shall be provided with an external metal oxide varistor (MOV) bypass arrester connected across the series winding.

3.4 An external oil sight gauge shall be provided which indicates oil level at 25°C ambient temperature.

3.5 An external position indicator shall indicate the tap changer position. The position indicator shall be mounted above the oil level and shall be slanted downward at a 45-degree angle for ease of reading from below when the regulator is pole mounted.

3.6 Regulators rated 668 amps and below shall include the ADD-AMP feature which will permit additional current carrying capabilities at reduced regulation as shown below, but not to exceed 668 amps. The ADD-AMP adjustment shall be located inside the position indicator faceplate to prevent inadvertent adjustment.

Regulation (percent)	Current (Percent of 55°C rating)
+/- 10.0	100
+/- 8.75	110
+/- 7.5	120
+/- 6.25	135
+/- 5.0	160

3.7 Mounting bosses shall be provided for the addition of lightning arresters adjacent to the source (S), load (L), and source-load (SL) bushings. The bosses shall be fully welded around their circumference. Spot welding is not acceptable.

3.8 All regulators shall have a 1" drain valve with sampling device and a 1" upper filter press connection.

3.9 A handhole with cover shall be provided on top of the regulator for inspection purposes and for access to terminals used for reconnection of regulators for lower-voltage operation.

3.10 Regulators rated 250 kVA and below shall be pole-mounted and provided with welded-on hanger brackets. Regulators rated 167 kVA and above shall be provided with a base suitable for securing them to a pad or elevating structure. All regulators must be capable of being secured to elevating structures.

3.11 Regulators witb pole-mounting hanger brackets shall be provided with two 1/2" - 13 UNC welded ground bosses located diagonally opposite from each other. Regulators with substation base mounts shall be provided with two ground pads located diagonally opposite from each other. Each pad shall have two 1/2" - 13 UNC ground provisions. All grounding provisions are to be located near or on the base of the regulator.

3.12 Each regulator shall be provided with two laser-etched nameplates, one mounted on the control enclosure and the other mounted on the regulator tank. The nameplates shall have the manufacturer code and serial number barcoded with "3 of 9" coding with a 0.25" minimum height.

4. REGULATOR CONTROL

4.1 The regulator control panel shall be mounted in a weather-resistant enclosure which is capable of being padlocked. The control enclosure shall have an external 1/2" - 13 UNC welded ground boss.

4.2 The control panel shall be hinge-mounted and designed for easy inspection and replacement. The front panel assembly shall be constructed to provide direct control interchangeability without requiring removal of the control enclosure. Visible means

shall be provided to de-energize the control and short the current transformer prior to control testing or removal.

4.3 All leads in the control shall be either color coded or labeled for easy identification.

4.4 All printed circuit boards shall be conformal coated for fungi and moisture protection.

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b. A three-position AUTOMATIC-OFF-MANUAL control switch which allows automatic or manual operation of the regulator, or allows the control to be turned off. Supervisory motor control shall be permitted only when the switch is in the AUTOMATIC position.

c. A spring-loaded three-position manual RAISE-LOWER toggle switch, which shall only be active when the AUTOMATIC-OFF-MANUAL switch is in the manual position.

d. A position indicator drag hand reset switch, located on the front panel.

e. A neutral indicating light, which is actuated via the tap changer to provide neutral indication.

f. A six-digit operations counter, which counts every tap change.

g. Separate motor and panel fuses, which are replaceable from the front panel. Fuse size shall be clearly marked below each fuse. One set of spare fuses shall be included in the control enclosure.

h. A means to indicate whether the voltage is inside or outside the set voltage band.

i. Voltage test terminals, which connect to the load side (L bushing) of the regulator.

j. External voltage source terminals, which allow control and tap changer operation from an external 120 vac source. A means shall be provided to prevent energizing the high-voltage bushings from the external source.

k. Control knob locking devices which prevent inadvertent adjustment of settings. The locking device shall be operable with a flat head screwdriver.

4.7 The control shall have provisions for setting the following parameters:

a. Set voltage shall be adjustable from 105 to 135 volts in increments no larger than 1 volt.

b. Set voltage bandwidth shall be adjustable from 1 to 6 volts in increments no larger than 0.5 volts.

c. Time delay shall be adjustable from 10 to 120 seconds in increments of 10 seconds.

d. Line drop compensator settings consisting of resistance and reactance which shall be individually adjustable from 0 to 24 volts. A means shall be provided to set the polarity of these settings.

4.8 The control shall have provisions to allow remote override of regulator operation via discrete (analog) supervisory control. Terminals shall be provided on the back panel as follows:

For motor raise:	Two terminals for normally-open, momentary-close contacts.
For motor lower:	Two terminals for normally-open, momentary-close contacts.
For auto inhibit:	Two terminals for normally-closed, latch-open contacts.

5. TESTING

All regulators shall be tested in accordance with the latest ANSI standards. In addition, every voltage regulator shall receive an impulse test at 100% rated BIL on the source (S) and source-load (SL) bushings to assure full integrity of the insulation system.

Meter Specifications

Power Quality Meter (Reliable Power Meters)

Specifications for a Comprehensive, Multifunction, Power Analysis and Recording System for Monitoring of Electrical Power.

1. General Specifications

The following specifications describe a Power Analysis and Recording system (PAR) which provides the following measurements and capabilities.

1.1 Power disturbance analysis including capture and measurement of: voltage impulse wave-forms, sags, swells, wave-shape faults, frequency deviations, True RMS voltage, True RMS current, and flicker, with simultaneous capture of current during the voltage event.

1.2 Harmonic measurements of voltage and current wave-forms to the 63rd harmonic.

1.3 Power consumption measurements to include watts, VA, VAR, power factor, demand watts, distortion power, and kilowatt-hours.

1.4 Real-time oscilloscope display of all voltage and all current wave-forms on three phase distribution systems including, neutral voltage, neutral current, and ground current.

1.5 Organization of events and summaries in a database which conforms to DBF file structures compatible with commercial Microsoft database programs which operate on IBM compatible PC's under Microsoft Windows, Windows 3.11 for Workgroups for communicating via Ethernet, Windows 95, or Windows NT.

1.6 Communication to an IBM compatible PC via Ethernet 10 base T.

1.7 All measurement systems shall be modular, and user upgradeable. All measurement systems when installed on the PAR's internal hard disk, shall be fully operational, functional, and available at all times. All measurements shall be made simultaneously

without the need to change hardware or software modules. Instruments which require changes of hardware or software modules, or PCMCIA memory cards to enable different measurement functions will not be considered acceptable.

2. Physical Characteristics

2.1 The PAR system shall consist of a monitoring unit the monitor which captures and records power measurements and a separate controller (or IBM compatible PC) the controller to retrieve and analyze captured data. The monitor shall be rugged, driproof, and operate in temperatures from 0° to 50° C. The monitor can be used either as a portable instrument or it may be permanently installed indoors or outdoors. (The manufacturer will provide a controller which shall be either a portable notebook IBM compatible PC or a permanent desktop IBM compatible PC *(specify.)*

2.2 The PAR monitor shall weigh less than 14 pounds, and be no larger than 13" x 8" x 3.5".

3. Operating and Installation Characteristics

3.1 The PAR will permit connection to an IBM compatible PC controller to retrieve and analyze data. The manufacturer will provide system software to access the data captured in the monitor from the controller and to analyze the captured information.

3.2 The system software shall operate on an IBM compatible PC or controller with an Intel 80486 or Pentium processor, a minimum of 8 megabytes of RAM memory, 3.5" floppy disk drive, 540 megabytes of non-volatile hard disk memory, MS DOS, and Microsoft Windows. The system software will be compatible with Microsoft Excel and Microsoft Word programs for spreadsheet and report writing tasks.

3.3 Manual threshold settings will not be required when installing the monitor. The PAR will automatically capture all events using automatic, adaptive thresholds.

3.4 The PAR shall provide the capability to correct voltage and current connection phase rotation errors and current clamp polarity errors during installation through software commands from an IBM compatible system controller.

3.6 The PAR shall possess a minimum of 4 MB internal RAM memory and a non-volatile mass storage hard disk drive of 540 megabytes, minimum, to store events, summary reports, and power calculations.

3.7 For portable instruments the voltage measurement cables shall be ten feet long and will accept interchangeable voltage probes to connect securely to different sized conductors. The manufacturer will offer (and manufacturer will provide - *specify*) in-line fuses for voltage measurements which are compatible with interchangeable voltage probes. Fuses shall be removable and rated at 0.25 amps and 200,000 AIC.

3.7a (Optional clause for permanently installed monitors replaces above clause) For permanently installed monitors the manufacturer shall provide terminal block connections for voltage measurements.

3.8 Current measurement cables shall be ten feet long and will accept the following clamp-on type current transformers (and manufacturer will provide - *specify #*) with ranges 0.01 amps - 5 amps RMS, 0.1 amps - 40 amps RMS, 1 - 1000 amps RMS, and 10 - 3000 amps RMS. The PAR will also operate with flexible type current transformers (and manufacturer will provide - *specify* #) with ranges of 1 - 100 amps, 10 - 1000 amps, and 50 - 5000 amps, in 24'' lengths for 100, 1000, and 5000 amp ranges, and 48" lengths for 1000 and 5000 amps ranges.

3.8a (Optional clause for permanently installed monitors replaces above clause) For permanently installed monitors the manufacturer shall provide terminal block connections for current measurements to accept a 0-5 amp signal from external CT's.

3.9 The installation of jumper cables between channels will not be required or permitted when monitoring three phase distribution systems.

3.10 Measurement cables will provide LED indication when a voltage probe is connected to an energized phase conductor and the voltage signal is measurable. LED's will indicate when the correct sized current clamp is being used and the current signal is measurable.

3.11 The PAR shall not require the use of thermal paper or other paper rolls, nor the use of floppy disks to store recorded data.

4 Measurement Characteristics

4.1 The PAR will have a minimum of nine simultaneous measurement channels, with a minimum of five channels to measure current on all phase conductors, neutral, and ground conductors simultaneously. Instruments which have less than four full time voltage channels and less than five full time current channels will not be considered acceptable

4.2 Voltage measurements will be covered in a single range with accuracy's as follows and current measurements with current clamps with ranges and accuracy's as follows:

Channels 1 - 3 (generally used for phase conductor measurements)
Voltage: 100 millivolts to 1000 Volts peak (707 volts RMS max.) □0.1% of full scale.
Impulses: 12 volts peak to 6400 Volts peak □2% of full scale.
Frequency: 45 - 65 Hz □0.1Hz

Channel 4 (for neutral conductor measurements)
Voltage: 10 millivolts to 100 Volts peak (70 volts RMS max.) □0.1% of full scale.

Impulses: 1.2 volts peak to 640 Volts peak □2% of full scale.

Channels 5 - 9 (for current measurements with current clamp)

Current: 0.01 - 5 amps RMS □0.1% of full scale.
0.1 - 40 amps RMS □0.1% of full scale.
1 - 1000 amps RMS □0.1% of full scale.
10 - 3000 amps RMS □0.1% of full scale.

OR for permanently installed monitors.

Current: 0.05 – 20 amps RMS □0.1% of full scale, via internal toroidal transformers.

4.3 Voltage and current wave-forms will be sampled with a 14 bit analog to digital converter at a rate of 7,680 times per second to provide 128 sampled points per cycle at 60 Hz.

4.4 Harmonic measurements on all channels shall be up to the 63rd harmonic to include amplitude and phase angle for each harmonic, % of fundamental, and individual harmonic RMS volts and currents. The monitor shall be capable of tracking and plotting any of the 63 harmonics for voltage or current over the monitoring period.

4.5 RMS, power, and harmonic measurements shall be made continuously on each and every cycle with an on board digital signal processor capable of performing a Fourier Transform to the 63rd harmonic in 100 microseconds. The minimum RMS measurement time shall be one cycle.

4.6 The following power measurements will be made on each and every cycle continuously: Watts, VA, VAR, true power factor, and displacement power factor.

4.7 The PAR shall also measure flicker to provide percentage voltage change and frequency of modulation to IEC 868.

4.8 In oscilloscope mode the PAR will provide vector addition and subtraction tools to add or subtract voltage or current wave-forms on an IBM compatible PC to identify ground loops, imbalances, and leakage currents.

4.9 The PAR shall be configured to make the following measurements *(specify)*:

- Power Quality. Measures: sags, swells, and wave shape fault events, RMS Volts, RMS amps, and frequency summaries. Transients to 1000 volts peak, 130 microseconds duration.

- Power Quality with peak detect of fast impulses. As above but adds high speed sampling of impulses at 2 MHz to measure impulses to 6400 volts peak, 500 nanoseconds duration and displays peak voltage.

- o Power Quality with high speed impulse waveforms. As above but adds high speed sampling of impulses at 2 MHz to measure impulses to 6400 volts peak, 500 nanoseconds duration and displays detailed high speed impulse waveforms and peak voltage.

- o Power Consumption. Measures: Watts, VA, VAR, PF (true and displacement), Demand, KWh.

- o Harmonics and Flicker. Measures: THD, harmonic spectrum to 63rd harmonic and displays magnitude and phase angle for each harmonic. Imbalance for voltage and current, and flicker to IEC 868. Tracking of all 63 individual harmonics, voltage and current, over time.

5.0 Data Analysis and Display

5.1 The PAR software will permit random access to the data for the selection of events and summaries without scrolling through data serially.

5.2 The PAR software will display disturbance event summaries as a percentage of nominal voltage against duration with respect to the standard power tolerance curves known as ANSI, ITIC or CBEMA. Events shall be plotted against tolerance curves using the "Full Disclosure" method. The display software will permit custom power tolerance curves to be drawn or edited, and superimposed at any time after capturing event data. Events shall also be plotted as a percentage of nominal voltage against time of occurrence.

5.3 The PAR will provide phasor diagrams to indicate the measurement connections, phase relationships, and amplitudes at the fundamental frequency.

5.4 The PAR will display power quantities including watts, VA, VAR, power factor, and distortion power in real-time.

5.5 The PAR will display the harmonic spectrum to the 63rd harmonic for a selected voltage or current waveform in real-time.

5.6 The PAR will provide tools to enlarge event waveforms and measure amplitude, rise-time, and ringing frequency.

5.7 All events will show date and time of occurrence.

5.8 Oscilloscope display screens will be continuously available while the PAR is recording power disturbance and power consumption information.

5.9 The manufacturer will provide software utilities to compress power survey database files.

6.0 Software Functions

6.1 The PC software to analyze power measurements and events shall run in the Microsoft Windows environment and the software shall have the capability to run simultaneously

with Microsoft Word and Excel. The software will allow direct export of graphs and data into Microsoft Word and Excel.

6.2 The manufacturer will offer (and manufacturer will provide - *specify*) a software function to automatically compile and generate a written report based on the captured power measurements and events.

6.3 The system software shall be fully compatible with the following commercial software applications: Microsoft Word, Microsoft Excel, Microsoft PowerPoint, Reliable Power Meters Omega Power Analysis System Software, Reliable Power Meters Professional Report Writer.

7.0 Miscellaneous Considerations and Options

7.1 (Portable instrument option *(specify)*) The manufacturer will provide a padded, water resistant, carrying bag to carry the PAR, voltage probes, current clamps plus a portable printer or IBM compatible notebook PC.

7.2 (Portable instrument option *(specify)*) The manufacturer will provide a rugged, high impact plastic shipping container for shipping the PAR by common carrier.

7.3 (option *(specify)*) The manufacturer will provide mounting brackets for permanent installation of the PAR monitor.

7.4 (option *(specify)*) The manufacturer will provide a locking security cable for the PAR.

7.5 (optional *(specify)*) The manufacturer will provide a portable printer, similar or equal to the Hewlett Packard deskjet with paper feed.

7.6 (optional *(specify)*) The manufacturer will provide 2 foot long flexible current transformers with the following ranges *(specify)* 100 Amps, 1000 Amps, 5000 Amps with 7 KHz bandwidth and 2% accuracy.

7.7 (optional *(specify)*) The manufacturer shall provide a high quality active matrix color display for permanently installed monitors suitable for installation into switchgear and panelboards.

7.8 (optional *(specify)*) The manufacturer will provide software to automate the collection of data from multiple remote instruments connected on an Ethernet network or connected to telephone circuits using modem or ISDN telephone communications, or a combination of both Ethernet and telephone communications, via a polling method. The software shall permit remote control and download of data from any individual instrument. Events captured by any single instrument will be reported on a central PC, and displayed against a power tolerance curve which represents the global activity of all the PAR's being polled. Power quality, power consumption or harmonics data from any individual PAR may be selected for viewing. The software shall permit downloading of data from remote PAR's either i) on demand, initiated by the user manually, or ii) automatically, at times

scheduled by the user. The software shall keep text logs of events, polling activity, and polling errors. The software shall also provide the ability to restart PAR's automatically after data has been downloaded. The software shall also provide alarming and annunciation features to alert key personnel to significant events. Events which fall outside power tolerance curves may be alarmed. Alarms may also be selectively issued on: Type I events, and/or Type II events, and/or Type III events as defined by the IEEE Emerald book. The manufacturer shall also have available software to perform predictive maintenenance functions.

7.9 The power analysis system shall be equal in all respects to The Reliable Power Meters "Power Recorder".

Revenue Meter (GE EPM-9650Q/Electro Industries Nexus 1250)

2.0 PRODUCT

2.1 Manufacturer

General Electric Company products have been used as the basis for design. Other manufactures' products of equivalent quality and operating features may be acceptable, at the engineer's discretion, if they comply with all requirements specified or indicated in these Contract documents.

2.2 Power Meters

A. Power meter shall be multi-function 3 phase solid state unit with ability to connect to either 3 phase, 4 wire or 3 phase, 3 wire delta circuits.

B. Voltage and current inputs to the meter shall conform to the following at a minimum:

1. Monitor shall accept input of four (4) independent voltage inputs and four (4) independent current inputs of the stated capacity.

2. Voltage input shall be 120 volts AC with available option for direct connection to voltage circuits of up to 600 VAC without the use of potential transformers.

3. Voltage input shall be optically isolated to 2500 volts DC. Shall meet or exceed IEEE 37.90.1 (Surge Withstand Capability)

4. Current input shall be rated for 5 amps with a continuous input capability of 10 amps.

5. Current inputs shall be solid U-Bolt stud inputs with a 10 second over-current rating of 100 amps and a 1-second over-current rating of 300 amps.

C. Power meter shall measure and report the following quantities at a minimum:

1. Voltage, both phase to neutral and phase to phase, for all three phases; Auxiliary voltage; Phase angles for each voltage relative to each other. One cycle, 50 millisecond and one-second readings shall be available simultaneously.

2. Current, phase A, B, C, N-measured, and N-calculated; Phase angles for each current relative to voltages. One cycle, 100 millisecond and one-second readings shall be available simultaneously.

3. Watts (total and per phase), VARs (total and per phase), VA (total and per phase), Power Factor (total and per phase) and Frequency. 100 millisecond and one second readings shall be available simultaneously.

4. Accumulated Watt-hr, VA-hr, and VAR-hr; Watt-hr received; Watt-hr delivered. VAR-hr and VA-hr reading shall be stored in each of the 4 quadrants of energy.

5. Power demand shall be calculated using four (4) different averaging methods: Thermal Average, Fixed Window Average, Sliding Window Average, and Predicted Average. Values for all averaging intervals must be available simultaneously.

6. Power meter shall provide updates of all voltage and current readings at intervals of 1 cycle, 50 milliseconds, and 1 second. Readings shall be available for both metering and control. All specified readings shall be made available via the RS-485 ports.

7. Power meter shall provide time-stamped maximum and minimum readings for every measured parameter.

8. Power meter shall provide coincident VAR readings for all maximum Watt readings.

D. Power meter shall provide the following accuracies:

1. Voltage accuracy shall be within less than 0.01% for the 1-second readings and less than 0.1% for the 50 millisecond readings.

2. Current accuracy shall be within less than 0.025% for the 1-second readings and less than 0.1% for the 50-millisecond readings.

3. Power and energy accuracy shall be within less than 0.04% at unity PF and within 0.06% at 0.50 PF.

4. Frequency accuracy shall be within less than 0.001 Hz.

5. Power meter shall meet ANSI C12.20 and IEC 687 accuracy requirements.

E. Power meter shall provide multiple digital communication ports and support multiple open protocols.

1. Meter shall include four (4) independent, digital communication ports. Each port shall be RS-485 architecture. Port 1 shall be user selectable as either RS-232 or RS-485 architecture.

2. Each port shall be user configurable with regard to speed, protocol, address, and other communications parameters. All ports shall support a maximum communication speed of 115k baud simultaneously.

3. One communication port shall be configurable as either a Master or a Slave port. The Master configuration shall enable the unit to act as an RTU and interface with other Modbus devices and EI I/O Modules communicating using Modbus RTU protocol.

4. Meter shall have an Ethernet port as an available option.

5. Meter shall have a 56K internal modem as an available option.

6. Meter shall offer both Modbus and DNP 3.0 open protocols as standard configurations. All instantaneous data, logged data, event data, power quality analysis and waveform information shall be available using these open protocols.

F. Power meter shall provide sequence of events capture and recording.

1. Meter shall have at least eight high-speed status inputs for capturing external events with one millisecond resolution

2. All high-speed status inputs shall be monitored at a user set rate from 1 to 8 samples per millisecond.

3. All changes in status shall be time stamped to the nearest millisecond and placed in an event log with time and event label information.

4. Event log shall enable users to recreate sequence of events involving external status points.

5. High-speed status inputs shall be able to trigger waveform recording to the waveform log.

6. Status inputs shall be configurable for event monitoring, pulse accumulation, or pulse synchronizing.

G. Power meter shall provide a separate IRIG-B input for time synchronizing to GPS time signal.

1. IRIG-B input shall accept un-modulated time signal input from a standard GPS satellite clock.

2. Time input shall enable time synchronizing to one millisecond and shall not be subject to network or other delays.

H. Power meter shall provide external display(s) to accommodate access to readings locally and/or remotely. Display(s) shall be LCD Touch-Screen and/or LED Display.

1. LED Display shall be three line, LED format. LEDs shall be 0.56-inch size. Display shall include 10-character alphanumeric segment to provide legend and scaling information for displayed values.

2. LCD Display shall be a touch-screen liquid crystal display. This display shall be 320 x 240 Pixels, blue on white-CCFL Backlight (cold-cathode florescent) to provide superior reliability in all light conditions.

a. The level of backlighting and contrast shall be adjustable.

b. The system display shall be equiped with an energy saver feature to extend the life of the display.

c. The LCD display shall display:

i. Time of Use Readings

ii. Real-Time Readings

iii. Phasor Diagrams

iv. Harmonic Spectrum (to the 127th order)

v. Real-Time Waveforms (all channels)

d. The LCD display shall be capable of interfacing with up to 16 Nexus power meters by addressing functions.

3. Display(s) shall connect to Power Meter via RS-485 communications architecture. The communication channel shall be isolated at the display to avoid the introduction of noise.

4. Display(s) shall be able to be powered directly from Power Meter or from an auxiliary power supply.

5. Display(s) shall communicate with Power Meter using Modbus protocol.

6. Display(s) must be capable of operating over common communications channels. It shall be capable of being connected up to 4000 feet from the Power Meter.

7. Display(s) shall be surface mounted for ease of installation.

8. Power meter shall be capable of supporting multiple displays.

I. Power meter shall be equipped with non-volatile RAM for recording logs and programming information.

1. Memory options of 512kB, 2MB, and 4MB shall be available.

2. Meter shall store historical trending data, power quality data, and waveform recordings in memory.

2. In the event of loss of control power, data stored in memory shall be retained for at least 10 years.

3. Memory shall be allocated to the various logging functions required. All logging features required shall be simultaneously available at the specified levels. Exercising any one feature at the specified level shall not limit exercising of any or all other features to their full, specified level.

4. Meter shall store all programming and set-up parameters in non-volatile memory. In the event of loss of control power, meter-programming data stored in memory shall be retained for at least 10 years.

J. When supplied with appropriate memory option, power meter shall provide historical data logging for trending of measured values.

1. Power meter shall contain two independent data logs.

2. Each historical log shall be user configurable. User may select measured quantities and reading intervals for each log.

3. Each historical log shall record at least 170 days of data where 5 readings are being stored every 15 minutes.

4. One of the historical logs shall be configurable for time of use recording.

K. The monitor shall internally record and store Time of Use.

1. The following Time of Use parameters must be included:

a. Twenty year calendar

b. Four seasons

c. Twelve Holidays per season

d. Four TOU schedules per season

2. The meter must display the following information in real-time when the TOU is enabled:

a. Current month accumulations

b. Previous month accumulations

c. Current season accumulations

d. Previous season accumulations

e. Total accumulations to date

3. Full four quadrant accumulations for Watt-hr, VAR-hr, VA-hr and coincident VARs during peak watt demand including max demand, shall be available for each tariff schedule, each season and for total accumulations.

L. When supplied with appropriate memory option, power meter shall provide extensive power quality monitoring capability.

1. Power meter shall measure and record the magnitude and phase angle of all harmonics through the 127th for all voltages and currents. Meter shall provide %THD and K-Factor for all channels.

2. All harmonic values shall be available through the digital communications ports in real time.

3. Power meter shall capture and record all CBEMA quality events.

4. CBEMA events shall be date/time stamped to the millisecond. Entries to CBEMA log shall include date/time stamp, duration, and magnitude information. The CBEMA log shall be downloadable through the digital communications ports.

5. The CBEMA log shall hold over 1024 events in a revolving FIFO format.

6. Power meter shall capture and record out-of-limit conditions in a log. Entries to Limits log shall be made anytime a monitored quantity exceeds the user set limit assigned to that quantity.

7. Entries to the Limits log shall be time stamped to the millisecond and include the measured quantity value and label.

8. The Limits log shall hold over 1024 events in a revolving FIFO format.

M. When supplied with appropriate memory options, power meter shall provide waveform recording to capture and record transients and quality problems on current and voltage waveforms.

1. Meter shall sample waveform at a user configurable rate of 16 to 512 samples per cycle (60Hz cycle).

2. Meter shall hold at least 96 records of waveform recording in non-volatile memory. Each record shall be a minimum of 8 cycles in duration at the highest sample rate or 64 cycles in duration at the lowest sample rate at not less than 16 bit resolution.

3. Each waveform record shall include pre-event and post-event data.

4. Waveforms shall be recorded with time resolution to within one (1) millisecond.

5. A waveform record shall be taken whenever the RMS value of voltage or current exceeds user-set limits.

6. User shall be able to configure meter so that a waveform record shall be taken whenever a status change occurs on any one of the eight high-speed status inputs.

N. Power meter shall have expandable auxiliary I/O capability. This capability shall allow the power meter to operate as an RTU for control and data acquisition.

1. Meter shall allow connection of external I/O modules.

2. Up to four (4) 8 channel external I/O modules shall be capable of being powered directly from the power meter. An auxiliary power supply shall be available to power additional I/O modules if needed.

3. External I/O modules shall be isolated from the power meter and from each other.

4. I/O modules shall connect to the power meter using RS-485 communication architecture and shall be capable of being placed up to 4000 feet from the power meter.

5. External I/O modules shall communicate with the power meter using Modbus protocol. Closed protocols shall not be accepted.

6. External output modules shall have four to eight channels each and shall allow the use of 0-1 mA outputs, 4-20 mA outputs, digital pulse outputs, and control relay outputs.

7. External input modules shall have four to eight channels and shall allow use of 0-1 mA inputs, 4-20 mA inputs, 0-5 VDC inputs, 0-10 VDC inputs, digital status detect inputs for status or pulse accumulation, and RTD inputs for temperature measurement.

8. External I/O modules shall be able to be added to the meter after installation to provide upgrade capability after the initial installation is complete. Changing the power meter shall not be required to provide this upgrade capability.

9. Meter shall record, data trend, and make available through communication ports all information from the external I/O modules.

O. Power meter shall be programmable by software supplied by the meter manufacturer.

1. Software shall have a user-friendly, Windows compatible interface.

2. Software shall operate on Windows 95, Windows 98, or Windows NT 4.0 operating systems.

3. Software shall include capacity to program meter, download meter, and analyze downloaded data files.

4. Software shall store all data in an ODBC compliant database. Data based storage shall include all log and waveform data.

P. Power meter shall be appropriately constructed to provide long life in abusive physical and electrical environments.

1. Meter shall be housed in an all-metal enclosure with no visible openings and no exposed circuit boards.

2. Meter shall operate successfully at temperature extremes from –40° C to +70° C.

3. Meter shall be UL listed.

4. Meter shall operate with control power from 90 to 275 volts AC/DC. Meter shall have a power supply option to operate with control power of 18 to 60 VDC.

5. Meter shall have a standard 4-year warranty.

Q. Power meter shall be General Electric / model: 9450Q with 4 Meg memory.

1. Approved model number is GE model 9650Q.

2. For expanded internal memory order option –512k for 512kB memory; -2MEG for 2 MB option; or –4MEG for 4 MB option.

G
TREE-TRIMMING MODEL™

This appendix describes the Tree-Trimming Model™. This is a software tool that models both the reliability impact and financial impact of right of way maintenance.

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Tree-Trimming Model™ (TTM™)

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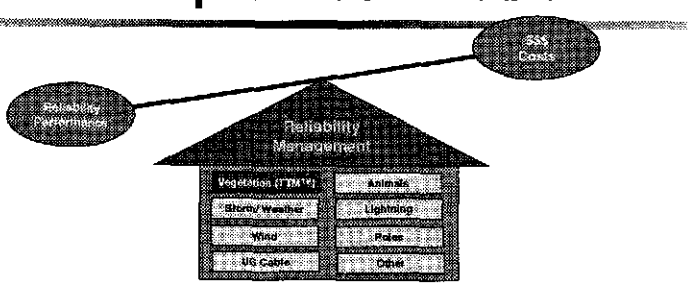
Purpose of the Model



- Determine the return in reliability for each dollar spent on tree trimming
- Use the model to support resource allocation decisions
  - Maximize performance (as measured SAIFI or SAIDI) for a given budget
  - Minimize costs required to achieve target performance (either SAIDI or SAIFI)
- Enhance the management of tree-trimming contractors

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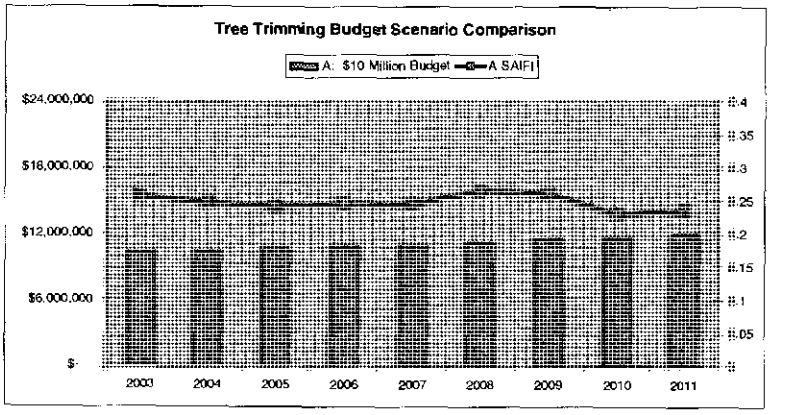
Model Analysis Example

Scenario A - $10M initial budget with 3% growth



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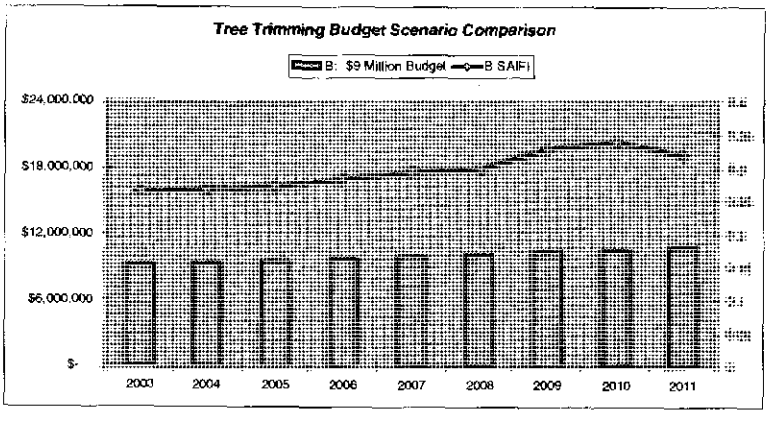
Model Analysis Example

Scenario B - $9M initial budget with 3% growth



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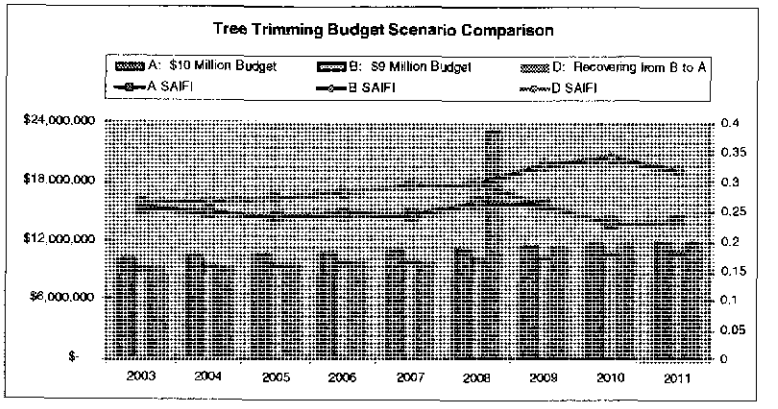
Model Analysis Example

Can I save money in the short term?

Yes, but it will cost more in the long run!



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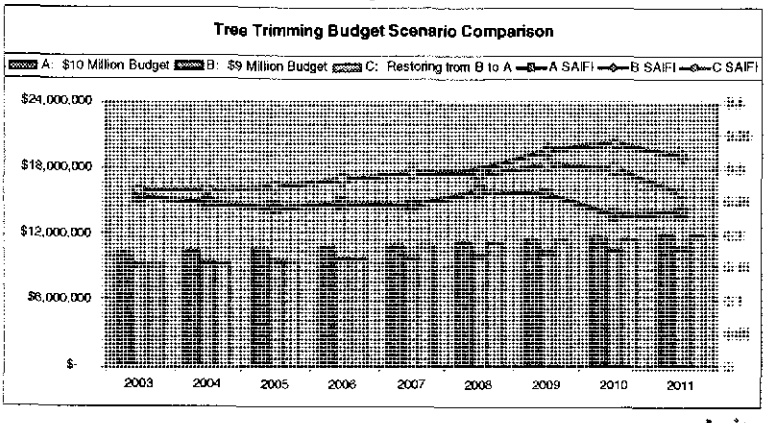
Model Analysis Example

How long does it take to make up for the budget reduction if I put that $1M back in the budget?

You may never catch up!



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Current Challenges & Model Benefits

Challenges:

- Budget cuts affect tree-trimming programs immediately
- State imposed reliability targets have to be met at minimum costs
- Changing clearances to meet predetermined trimming cycles does not work

Benefits of the Model

- Based on actual reliability data
- An objective way to develop optimal tree-trimming program
- Fast way to conduct scenario analysis and assess risks
- Supports resource allocation discussions with senior management

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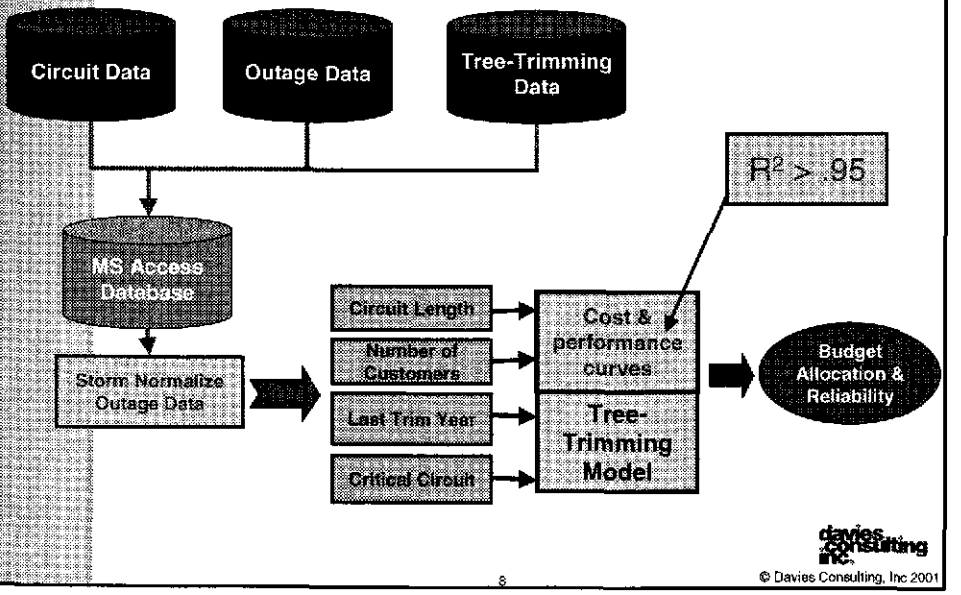
TTM™ Framework



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Cost and Performance Curves

Performance Curves

- ***Three different sets of curves are used depending on the customer density :***
  - **High (> 100 customers/mile);**
  - ***Medium (>25 and <100); and,***
  - **Low (<25)**
- **Each set consists of two curves:**
  - **Cases of interruption per mile**
  - **Customer minutes out per mile**

Cost Curves

- **The cost to trim a circuit increases with time after previous trim**
- **Assume that the clearance guidelines are consistent**
- **Cost is adjusted for inflation**

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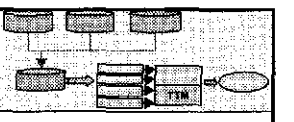
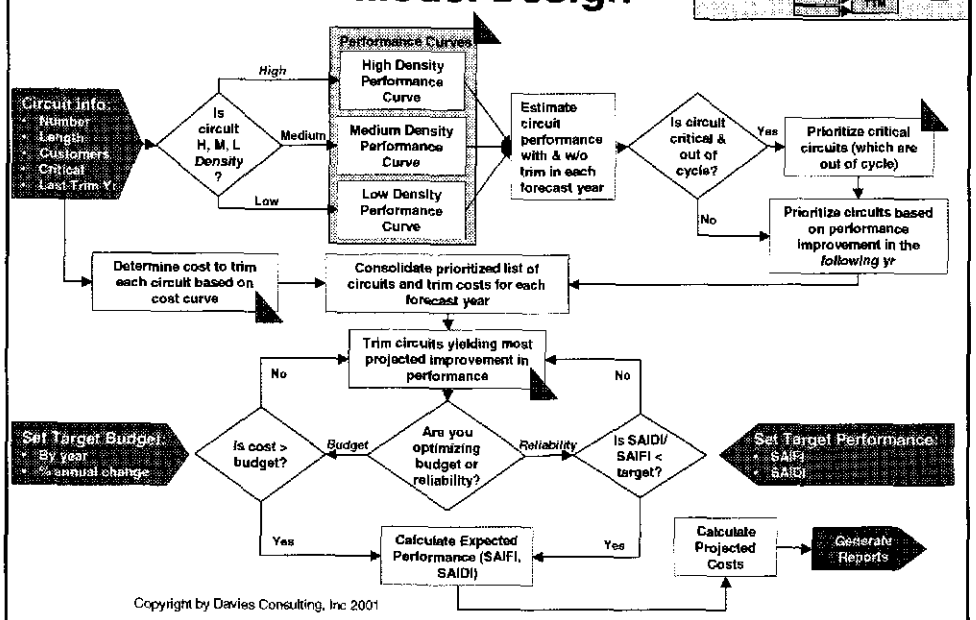
Model Design





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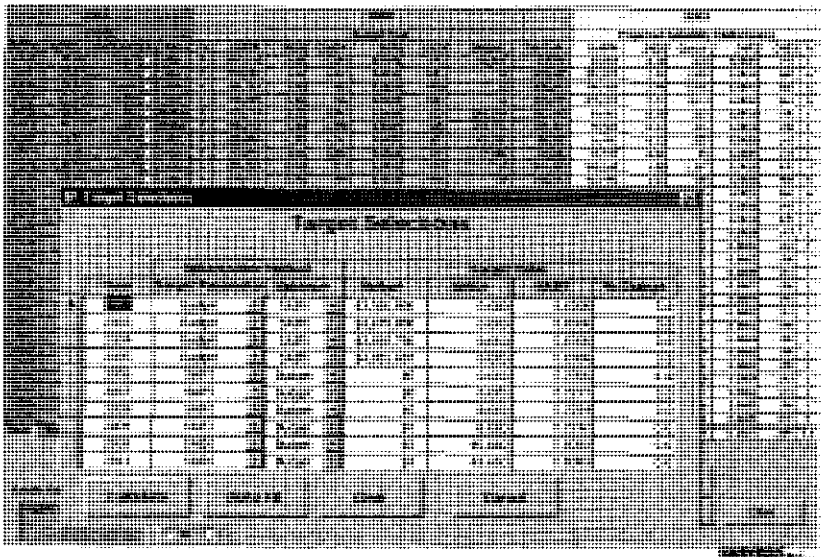
Model Interface



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Model Implementation Process

1. Obtain current circuit and historical outage and trimming data
2. Consolidate data into a single Access database
3. Identify any necessary model adjustments/ customizations (e.g., customer density groupings, circuit voltage breakdown, special reports, etc.)
4. Develop predictive performance and cost curves by each category (e.g., customer density) specific to company
5. Make necessary adjustments/customizations to the model
6. Update supporting documentation and manuals
7. Train staff to use TTM™ and conduct scenario analysis
8. Continue to gather data and update the predictive curves as the new and better information becomes available

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Summary of Benefits

- Not a theoretical model!!!—It is based on actual utility-specific reliability data
- Helps allocate scarce resources more effectively:
  - *To maximize system performance for a given budget*
  - To minimize the costs to achieve target reliability performance (SAIFI or SAIDI)
- Allows scenario ("what if") analysis in order to expedite decision-making
- Makes decisions and associated risks transparent

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I
STRATEGIC ASSET OPTIMIZATION

EPRI has a proprietary tool, called Strategic Asset Optimization (SAO) that has been used to determine the best regions where it makes sense to offer a distributed resource option to residential homeowners. Using utility maps (based on geographical information systems, GIS), we identify the regions where the distribution system is at or near its capacity to supply power. The power available from substations and on specific feeders typically comes from utility sources. Data on customer loads come from utility databases or can be obtained independently from third part databases. All of this information is displayed on an easy to read map, which shows the locations of regions served by an individual substation. Color coding shows the regions that are constrained and are limited to support additional load, as well as those regions where capacity is available to support additional load.

All the large industrial and commercial customers who are responsible for most of the power delivered by the feeder can be plotted by the system. Using knowledge of these customers, SAO can determine that many of them, because of the characteristics of their businesses would be suitable candidates for a distributed resources (DR) program.

The same analysis tool is used for a residential DR program. First, the SAO model is used to identify the utility regions that are at or are near overloading. Next the amount of the load attributable to large commercial and industrial customers is determined. The balance of the load in that region is the residential and retail loads. Using the utility databases, the locations of these sites are mapped. If these databases are not available from utility records, third party databases can be used to obtain the data.

Siting DR systems at these locations is done by applying a negative load at that site. SAO continues adding DR capacity to these locations until the feeder circuit has available load to supply to all customers. The type of DR systems and the capacity of each system is transparent to the model, and can be left to the discretion of the utility and the customers.

We can also use the SAO approach to identify future requirements for placing DR systems. Using data from the utility or the local or regional economic development authorities, SAO identifies the proposed sites for development and the anticipated loads. This information is again plotted on the maps in chronological fashion to identify the potential service areas that may be at risk as the region grows.

Use of the SAO tool provides an easy and visual means to target both regions of the utility service area and individual customers for DR programs. It can quickly and cost-effectively identify the impact of offering DR solutions. Its versatility is that the user can rapidly move

through many "what-if" scenarios to optimize the DR solution in terms of load reduction and which customers at which geographical locations the use of DR will have the greatest impact.

Based on Geographic Information Systems (GIS), EPRI has built information systems that interact with a utility's AM/FM, Customer Information System, Outage Management System, and other internal and external databases to enhance both strategic planning and operations. The models enable the utility to integrate data from various sources and visualize the relationships between the data sets. The resulting models are used to simulate new customer locations, analyze circuit and system reliability, investigate distributed generation deployment, plan customer marketing and conservation programs, and track operational issues such as distribution system maintenance. In the course of this GIS work, EPRI has worked with all major platforms including ESRI, Intergraph, SmallWorld, and other proprietary systems.

J
INCEPTION REPORT

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1 General Information

This report outlines the findings of the project team based on questionnaire responses, visits and meetings, and contributions by key utility personnel during site visits at the three utilities in the Philippines and during the Orientation Visit.

Further, this report will set forth the procedures to be followed throughout the remainder of the feasibility study for enhancing reliability and power quality. It will set the direction for the allocation of time and resources by the EPRI-PEAC project team in conducting the subsequent Tasks, and request the concurrence of the contracting utilities through their acceptance of this Inception Report.

Data Collection Overview

Data has been collected from the three utilities through questionnaires, site visits, and consultations during the Orientation Visit. By moving the Orientation Visit forward in the schedule, the data gathering phase has been lengthened, and the exchange of information, as well as communication of expectations and goals have been made more extensive than originally planned. In short, EPRI-PEAC and the three utilities know each other well now. The EPRI-PEAC project team has gained insights into the areas that merit the most attention in order to maximize the value of the feasibility study to each of the three utilities, collectively and in their particular circumstances. And the three utilities have made their priorities known to EPRI-PEAC.

For each of the tasks enumerated in the TOR, data has been collected and reviewed at a level sufficient to determine their impact on power quality and reliability, and their overall importance to meeting the basic objectives of the feasibility study.

Purpose

It is the purpose of this report to focus attention on those items in the TOR that directly impact power quality and reliability, after analyzing the adequacy of systems at each of the utilities. The scope of the feasibility study will be focused in those areas with significant impact on power quality and reliability. Less emphasis will be placed on those areas with minimal PQ and reliability impacts. In addition, the scope of the study will be expanded into related areas that were not included in the original TOR, such as Outage Management Systems, Dispatch Center Operations, and the relationship between reliability measurements and indices and regulatory standards. By doing so, EPRI-PEAC will make an additional contribution to improvements in infrastructure, IT systems and operations. Thus, substantial additional benefits will be realized by the three utilities and greater opportunities will be identified for the purchase of US-sourced goods and services.

In focusing on the primary objective — namely, improving reliability and power quality — it is necessary to allocate a majority of the budget and resources directly to Tasks related to the Engineering and System Reliability portion of the TOR. At the same time, the other four areas enumerated in the TOR must be revisited in terms of complementing that emphasis, and must be

approached in terms of their impact on overall system reliability and power quality. For example, project financing must be the center of the Accounting and Finance discussion.

2 Work Plan and Tasks

The study's major areas of focus are shown below. These are the areas selected for further review and analysis. The other areas listed in the TOR have been reviewed and are considered adequate as they relate to power quality and reliability.

Engineering and System Reliability

- Specific Reliability Enhancement Techniques
- Metering Requirements
- Technology Procurement Recommendations
- Evaluation of Current Design Practices
- Evaluation of Distribution Equipment in Use
- "Roadmap" to Meeting Reliability Requirements in the Philippine Distribution Code

Information Technology

- Migration to Target IT infrastructure
- Standard Software Methodology
- IT Direction
- "Roadmap" to Transition under Deregulation
- Use of Intranet and Internet
- Software – "Off the Shelf" versus Custom
- IT Issues – Substation Monitoring, Trouble Call System, GIS support

Finance and Accounting

- Capital Budget
- Capital Project Reporting
- Outage Tracking Systems
- Implementation Plan – Internally Generated Resources
- Premium Power Pricing

Construction and Maintenance Operations

- Current Mapping Capabilities
- Changes in Equipment
- Vegetation Management
- Equipment Monitoring Technologies

Customer Services

- Trouble Notification
- IT Links (LAN/WAN)
- Information Service System
- Communication System

3 Findings of Questionnaire and Site Visit

Common Information

The engineering practices used by the three utilities for facility design are comparable to those used by distribution utilities in the United States. All three utilities avoid using automatic reclosing on feeder breakers and most often use fuses to protect three-phase laterals. Stations appear to be well designed and maintained.

There is a strong, immediate need for all three utilities to acquire, install and maintain comprehensive GIS/AM/FM programs. GIS/AM/FM systems should be looked upon and utilized as the unifying technology for operational and management functions. The requirements of the three utilities with respect to GIS/AM/FM systems varies from further integration into other systems to installation of a new system.

The IT portion of the study will focus on the integration of GIS with an Outage Management System and Customer Account System.

Telecommunications infrastructure will continue to be examined for its adequacy in supporting improvements in distribution system automation, especially between substations and operations. Issues remain with the cost of service from existing providers, especially leased lines. Alternatives for telecommunications, such as fiber optic backbones and spread spectrum radio will be explored.

Further inquiry of telecommunications links to key customers will be included as the study progresses, especially to support power quality recommendations.

For utilities using the distribution circuit analysis modules offered by Synergee, we offer a preliminary recommendation for the acquisition of the reliability module. This module provides the capability to model the reliability of feeders. Once a feeder is modeled, "what if" scenarios can be performed to determine the relative improvement in reliability.

Under deregulation the National Power Corporation must be accountable for maintaining certain standards on voltage and frequency. Recommendations will be made with respect to standards and monitoring technology.

VECO Specific Information

The following findings are specific to VECO. They have been divided into groups according to the area of study specified in the TOR.

Engineering and System Reliability

This section was removed due to considerations of proprietary data.

Information Technology

This section was removed due to considerations of proprietary data.

Finance and Accounting

This section was removed due to considerations of proprietary data.

Construction and Maintenance Operations

This section was removed due to considerations of proprietary data.

Customer Services

This section was removed due to considerations of proprietary data.

Documents and Information Collected

The following is a list of the information collected from VECO during the Site Visit. This information, along with data collected via the initial questionnaire and during the Orientation Visit, was used in determining the areas that require further study. This data will also be used in focusing the remainder of the project to meet the needs of VECO.

Collected Documents

- Financial Statements 2001 (audited)
- Financial Projections
- Operating Budget
- Capital Expenditure Plan
- Organization Chart – Accounting & Finance Departments
- Organization Chart – Customer Service Department
- Organization Chart – Administration Department
- Information System Plans
  - Customer Service
  - Meter Reading
  - Billing
  - Collection
  - Inspection & Connection
- Information System – Equipment & Systems (overview)
- Capital Expenditures for 2001 – Expansion/Upgrade Projects
- Construction and Maintenance Policies
- Metering Points (sample report)
- Line Mile Report (sample)
- Electric System Operation and Maintenance Procedure
- Construction Standards

- Substation Report (example)
- Transformer Report (example)
- Customer Assistance and Information System (description)
- CAIS Performance Monitoring System (description)
- Customer Profile (example)
- Customer Profile (example, data record form)
- Customer Call List (sample form)
- Dispatch Procedures (sample forms)
- Wide Area Network (description)
- Work Order (sample form)
- Work Order Monitoring Module
- Communications Costs (spreadsheet)
- Customer Inquiry Procedure (overview)
- Fiber Optic Backbone (study)
- Revenue Collection Monitoring System (description)
- Estimate of System Losses Due to Pilferage
- BOD Presentation – February 18, 2002
- Performance Standards – Distribution and Suppliers
- Performance Standards – TRANSCO
- Uniform Rate Filing Requirements
- Philippine Grid Code, September 2001
- Philippine Climate Change Mitigation Program
- Outage History
- Circuit Maps (examples)
- AM/FM Data (examples)

4 Focus of Work

The areas of focus will be reordered into the following areas, with deliverables structured accordingly. The remaining manpower and budget will be concentrated on delivering value-added recommendations to the three utilities in these areas. The recommendations will include detailed costs, specifications, and implementations methods.

Topics to be Studied

The following topics related to the improvement of the reliability of the distribution system will be studied:

- Collection of interruption data
- Calculation of Indices
- GIS from AutoCAD - GENMAP version, single or multiple users; conversion of GENMAP
- Modification of distribution circuit coordination techniques
- Development of a plan to meet reliability and power quality regulations set forth in the Philippine Distribution Code
- Use of additional software analysis packages to better plan reliability enhancements to the distribution system
- Outage Management Report System
- Evaluation of fiber optic communication system to support Line Current Differential Relay System
- Integration of Work Management System with Accounting Operations Reports
- Extension of SCADA to two remaining substations

Excel Spreadsheet

In addition, an Excel-format spreadsheet will be developed for use by the utilities. The purpose of the spreadsheet will be to model and analyze the anticipated improvements in reliability indices assuming one or more reliability-enhancement methods will be implemented (e.g., how much SAIFI is reduced when installing line reclosers, or how much CAIDI is reduced by the installation of fault indicators/monitors). The spreadsheet will use a "typical" distribution circuit for this analysis. It is not intended that this spreadsheet replace more complicated and rigorous reliability analysis packages available from various software vendors.

Technical Seminar

A technical seminar will be developed to help educate utility personnel on the methods used in developing the final report. Topics will include: analysis of reliability data, impact of reliability improvement techniques, and a power quality primer. All three utilities involved in the study expressed interest in learning more about power quality. Therefore power quality will be included in the seminar.

Financing

Internal sources of funding to support the Capital Budget, especially those capital expenditures recommended as part of this study, will be examined. Also, possible changes to the rate structure – Premium Power Pricing - will be examined as a source of funding for power quality expenditures. External sources of funding, such as borrowing from local and international banks, will also be investigated.

Resources

The following personnel will be called on as needed in analyzing PQ & reliability options and preparing the preliminary and final reports:

Name	Title	Power Systems Experience in Years
Charles Perry P.E.	Sr. Power Systems Engineer EPRI PEAC Project Manager	13
Carl Miller P.E.	Sr. Power Systems Engineer	22
Tom Short	Sr. Power Systems Engineer	12
John Harding P.E.	Consultant	32
James Reilly	Consultant	7

Schedule

The schedule for the creation and delivery of the final report is as follows:

	Task	**Timeframe**
Task 5	Analyze Data and Formulate Recommendations	August 15, 2002
Task 6	Preliminary Report Delivered to Client Utilities	September 1, 2002
Task 7	Review Utility Questions, Requested Changes, Additions and Deletions, and Prepare for Reporting/ Seminar Trip	October 25, 2002
Task 8	Perform Reporting and Seminar Trip	Oct. 28 – Nov. 8, 2002
Task 10	Final Report Delivered to Client Utilities	November 15, 2002

Final Report Outline

The Final Report will be tailored to each utility. Three individual reports will be developed, one for each utility, to ensure the recommendations are utility specific. The following outline describes the major sections to be used. Developing a more specific proposed outline at this time is unfeasible and might reduce the flexibility in addressing utility concerns that may arise during the study.

- Introduction
- Methodology
- General Findings
- Company Specific Reports and Recommendations
- Recommendations for Future Projects

5 Conclusion

The purpose of this report is to report on the results of the questionnaire, the site visit, and the US orientation visit. Further, it provides the direction of further work associated with this project. It also serves to focus the project on those areas that have the most effect on reliability and power quality, as requested by the utilities.

This report completes Tasks 1 to 4 (Phase 1) of the feasibility study. Task 9, the US Orientation Visit, has also been completed.